Decision **PROPOSED ALTERNATE DECISION OF COMMISSIONER BROWN (MAILED 4/22/03)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.	Rulemaking 02-01-011 (Filed January 9, 2002)

ORDER ADOPTING COST RESPONSIBILITY SURCHARGE MECHANISMS FOR MUNICIPAL DEPARTING LOAD

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ORDER ADOPTING COST RESPONSIBILITY SURCHARGE MECHANISMS FOR MUNICIPAL DEPARTING LOAD

I. Summary

Today's decision adopts policies and mechanisms to implement cost responsibility surcharges applicable to "Municipal Departing Load" (MDL), within the service territories of California's three major electric investor-owned utilities (IOUs): Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E). As defined in this order, MDL refers to departing load served by a "publicly owned utility" as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts.[1]

The departing load that is the subject of this decision does not address "Customer Generation" Departing Load which was the subject of a separate phase of this proceeding, and D.03-04-030. The surcharge mechanisms and associated principles adopted in this order are patterned after those previously adopted for Direct Access (DA) customers in Decision (D.) 02-11-022.

Parties have used different terms for the charges at issue in this order, including expressions such as "nonbypassable charge," forward costs, and "exit fee." For the sake of uniformity, clarity, and consistency with D.02-11-022, we shall use the term "cost responsibility surcharge" (CRS) as a comprehensive term in referring to the various cost components that are applied to MDL as discussed in this order.

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[1] This order does not address or prejudge cost responsibility issues for load related to "community choice aggregation: as specified in Assembly Bill 117.

As context for addressing the MDL CRS issues, we review pertinent background leading to this order. This proceeding was opened to address the suspension of DA pursuant to legislative directive, as set forth in Assembly Bill (AB) No. 1 from the First Extraordinary Session of 2001-2002 (AB 1X). (*See* Stats. 2002, Ch. 4.) DA suspension was ordered as part of Legislative action to address the serious situation in California that developed beginning in the summer of 2000 when PG&E and SCE became financially unable to continue purchasing power due to extraordinary increases in wholesale energy prices.

Emergency legislation[2] enacted on January 17, 2001 required that DWR assume responsibility for procuring electricity on behalf of the customers in the service territories of the California utilities.[3] The Legislature enacted AB 1X on February 1, 2001, authorizing DWR to continue to meet the utilities' net short requirements through December 31, 2002. DWR thus began buying electricity on behalf of the retail end use customers in the service territories of PG&E and SCE on January 17, 2001, and of SDG&E on February 7, 2001.

Among its provisions, AB 1X mandated the suspension of the right to acquire service. In compliance therewith, the Commission issued D.01-09-060, suspending customers' rights to acquire DA after September 20, 2001. In D.01-09-060, we stated, however, "that we may modify this order to include the suspension of all direct access contracts executed or agreements entered into on or after July 1, 2001." (D.01-09-060, pp. 8-9.)

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[2] *See* Senate Bill 7, First Extraordinary Session (SB 7X)

[3] On January 17, 2001, Governor Davis issued a Proclamation that a "state of emergency" existed within California resulting from dramatic wholesale electricity price increases.

On January 14, 2002, the instant Rulemaking (R.) 02-01-011 was initiated to consider, among other things, whether a DA suspension date earlier than September 21, 2001 should apply.[4] On March 27, 2002, we issued D.02-03-055, determining that the DA suspension date should remain in effect as "after September 20, 2001."

In D.02-03-055, we also required that bundled service customers not be burdened with cost shifting due to customers' migration from bundled to DA load between July 1, 2001 and September 20, 2001. Prevention of cost shifting requires that surcharges be imposed on DA customers so that "bundled service customers are indifferent."[5] As stated in D.02-03-055:

> "There would be a significant magnitude of cost-shifting if DWR costs are borne solely by bundled service customers, and direct access customers are not required to pay a portion of these costs that were incurred by DWR on behalf of all retail end use customers in the service territories of the three utilities during a time when California was faced with an energy crisis."[6]

Proceedings were accordingly initiated to implement the necessary surcharges on DA load to prevent such cost shifting.[7] At the prehearing

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[4] The administrative record relating to these specific issues in Application (A.) 98-07-003 *et al.* was incorporated into this rulemaking. Judicial notice was also taken of specific information in the DWR Revenue Allocation Proceeding A.00-11-038 *et al.* (*See* Letter of January 25, 2002, to the parties that accompanied the Draft Decision of ALJ Barnett.)

[5] D.02-04-067, pp. 4-5.

[6] *See* D.02-03-055, Finding of Fact 3.

[7] Proceedings to determine DA CRS were initiated by an ALJ ruling issued December 17, 2001 in A.98-07-003. By joint ruling on December 24, 2001, the issue of DA cost responsibility was transferred from A.98-07-003 to A.00-11-038 *et al.* Finally,

Footnote continued on next page

conference (PHC) on February 22, 2002, certain parties argued that cost shifting also implicated "Departing Load" (DL) customers. An administrative law judge (ALJ) ruling issued on March 29, 2002, prescribed that this proceeding would thus consider cost responsibility relating to DL customers. The ruling also stated: "In order to ensure that the Commission is able to consider a fully compensable surcharge, a record must be developed that takes into account all possible cost responsibilities including but not limited to DWR purchase costs . . . attention will be focused on how such cost responsibility can be formulated."[8]

In D.02-04-067, the Commission expressly stated that DA cost responsibility will take into account relevant non-DWR as required by AB 1X and other statutes (*e.g.*, AB 1890). (*See* D.02-04-067, Ordering Paragraph (OP) 1e.) An ALJ Ruling issued on April 5, 2002 confirmed that the "full range of costs" was also to be considered in determining the responsibility for DL customers that would otherwise cause cost shifting to bundled service customers.

Parties filed prehearing opening briefs on April 22, 2002, and reply briefs on May 6, 2002 on legal issues relating to the Commission's authority to impose cost responsibility charges both on DA and DL customers. Opening testimony was mailed on June 6, 2002 and reply testimony was mailed on June 20, 2002.

By ALJ oral ruling on the first day of hearings, DL issues were deferred to a later hearing phase. Parties submitted supplemental testimony on September 11, 2002 and supplemental reply testimony on September 23, 2002

D.02-04-052, issued on April 22, 2002, transferred consideration of cost responsibility issues from A.00-11-038 *et. al.* to R.02-01-011.

[8] ALJ Ruling of March 29, 2002, p. 5, emphasis added.

relating to DL issues. Evidentiary hearings on DL issues were held on October 7, 9-11, 15 and 18, 2002.

During the course of DL hearings, certain parties entered into settlement discussions on issues relevant to DL served by customer generation. The disposition of Customer Generation DL was the subject of a separate decision, D. D.03-04-030. This order addresses remaining DL CRS issues that relate to load served by publicly owned public utilities (*i.e.*, municipal utilities and irrigation districts, as defined in Section 9604(d). Post-hearing opening briefs on MDL CRS issues were filed on November 25, 2002, and reply briefs were filed on December 6, 2002.

Parties participating in the MDL CRS phase of the proceeding included the IOUs, the Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN), and various interests representing municipalities and irrigation districts, including the California Municipal Utilities Association (CMUA).[9] City of Corona (Corona), Merced Irrigation District (Merced), Modesto Irrigation District (Modesto), and Westside Power Authority (WPA).

II. Overview of Issues

A. Parties Positions

The IOUs, ORA, and TURN argue that the Commission has legal authority to impose CRS on MDL customers, and must do so in order to hold MDL responsible for their share of DWR and IOU costs. For purposes of

[9] CMUA is an industry association representing "publicly owned utilities," comprised of 26 electric distribution utilities serving 30% of the electric load in California. The term "publicly owned utilities" refers to public agencies listed in Public Utilities Code Section 9604(d), including among others, municipalities, municipal utility districts, public utility districts, and irrigation districts.

identifying customers that would be subject to the CRS, PG&E defines MDL, based on its Commission-approved tariffs,[10] to encompass customers within its service territory that purchase or consume electricity supplied and delivered by a publicly owned utility after January 17, 2001, such as a municipal utility district or an irrigation district. PG&E specifically includes "new municipal load" that is added within its service territory on or after January 17, 2001, but that purchased or consumed electricity supplied and delivered by a new or expanding publicly owned utility.[11] PG&E does not include current or future load served by a publicly owned utility within the publicly owned utility's ***exclusive*** service territory in its definition of municipal departing load.

SCE also relies on its tariffs[12] in defining MDL as that portion of load for which the customer, on or after December 20, 1995, "(1) discontinues or reduces its purchases of electricity supply and delivery services from SCE; (2) purchases or consumes electricity supplied and delivered by sources other than SCE to replace such SCE purchases; and (3) remains physically located at the same location or within SCE's service territory as it existed on December 20, 1995."[13] SCE's definition includes load regardless of whether it is in an annexed area of a municipal utility or moves from one portion of its system to another that has been annexed by a municipal utility.

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[10] *See* PG&E Electric Preliminary Statement, Section BB, except PG&E applies a departure date for MDL of January 17, 2001, instead of the tariff date of December 20, 1995.

[11] *See* PG&E Opening Brief, pp. 1–2; *see also* PG&E Preliminary Statement BB.6 (Ex. 106).

[12] *See* SCE Tariff Preliminary Statement Part W.

[13] SCE, Exh. 79, p.1; SCE, Exh. 129, pg. 1; Part W lists three exemptions from the DL definition.

SDG&E defines departing load as the electric load of any of IOU bundled customers that reduce or terminate their service from the IOU, yet continue to use electricity from another source to serve the reduced or terminated electric load. SDG&E cites customer load that is served by a new or expanding municipal entity that otherwise would be served by the IOU as an example of MDL. SDG&E believes that municipalization in the form of community aggregation under DA should pay the same surcharges and be subject to the same DA suspension rules as other DA customers for the same reasons.

PG&E and SCE propose that DWR bond and power charges apply to MDL customer load served by a municipality or irrigation district that was located in the IOU service territory as it existed on January 17, 2001, the date that DWR began procuring power concurrent with enactment of Senate Bill 7, First Extraordinary Session of 2001-2002 (SB7X).[14] PG&E and SCE propose that tail CTC be applied to MDL based upon whether the load received service within the IOU service territory as it existed on December 20, 1995. SCE also proposes that MDL pay an Historic Procurement Charge (HPC), based on an effective date of March 29, 2002, as described in Section IV.D.

SDG&E proposes that the DWR surcharge apply to any customer load served by municipal utilities that begin serving this load in any of the IOU's service territories on or after July 1, 2001.[15] SDG&E believes that the payment of a DWR surcharge, together with the payment of the ongoing Competition

[14] SCE / Collette, RT. Vol. 16, pp. 1533-1534.

[15] This date is the reference point for determining bundled customer indifference to the migration of DA load between July 1 and September 20, 2001.

Transition Charge (CTC), will achieve bundled customer indifference with respect to MDL.

The IOUs' proposals are intended to charge MDL customers for the costs they cause DWR and the utilities to incur, to protect bundled customers from cost shifting, and to impose responsibility for CTC in accordance with state law. ORA likewise argues that this proceeding must be resolved so as to ensure that bundled service customers are indifferent and that costs attributable to departing municipal customers are not shifted to bundled ratepayers. To that end, ORA proposes that the Commission impose a surcharge on customers who departed bundled IOU service after January 17, 2001, to be served by a municipality.

Municipal parties generally deny that the Commission has jurisdictional authority to impose CRS on municipal utility customers. To the extent that the Commission nonetheless issues an order imposing costs, municipal parties present various proposals to limit costs that would be imposed. CMUA acknowledges that at least a colorable basis exists to apply certain of the cost responsibility surcharges to Municipal Departing Load. CMUA argues that any surcharges applicable to MDL should only be those that are expressly set forth in legislation, including CTC and the historic DWR costs.

For purposes of identifying customers that would pay the CRS, CMUA defines MDL as follows:

> Load that has previously been interconnected with and received electric service from an investor-owned utility but, subsequent to December 20, 1995, becomes served by a publicly owned utility, either through the acquisition of facilities previously owned by an investor-owned utility or through a newly established interconnection with the load.

CMUA opposes any surcharges being applied to "new municipal load," associated with new facilities that have never been connected to an IOU system, as explained further in Section VA below.

Merced and Modesto represent the interests of irrigation districts, which are a special category of publicly owned utilities. The irrigation districts likewise claim that the Commission lacks jurisdiction to impose a CRS on customers served by irrigation districts. Merced argues that to the extent any charges are imposed on irrigation districts, they be limited to (1) DWR Bond Charge (at the level proposed in the Settlement Agreement in the Customer Generation phase of the proceeding); and (2) tail CTC, as defined and limited in Public Utilities Code[16] Section 374(a). Section 374 contains a 75 megawatt (MW) exemption from CTC for Merced.

Merced argues that no ongoing DWR power charges should be assessed on irrigation districts because DWR accounted for the fact that some load would leave the utility system for a number of reasons, including to take service from another provider, such as an irrigation district. Merced also opposes surcharges to recover historical utility undercollections. Merced argues that a number of policy considerations mitigate against imposing surcharges on irrigation district load. Merced notes that the Commission and CEC have encouraged irrigation district participation in the marketplace, and argues that the Commission should not interfere with longstanding irrigation district statutory authorizations to provide a variety of electric services by imposing surcharges.

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[16] All statutory references are to the Public Utilities Code, unless otherwise noted.

Merced opposes the use of an effective date of January 17, 2001 for applicability of any DWR charges to municipal load customers. Merced argues that any DWR liability should only apply to customers who left an IOU after March 29, 2002. This date coincides with the issuance of the ALJ ruling prescribing that this proceeding would consider cost responsibility for departing load customers. Merced argues that March 29, 2002 is the earliest date that DL customers were notified of the potential of surcharges relating to DWR costs, and that, prior to the ruling, the Commission had limited the potential reach of any surcharges to DA customers.

Corona goes even farther, arguing that municipal customers have not yet received sufficient notice that they may be responsible for a CRS, and that such notice cannot become effective until or unless express statutory authority to impose a CRS on municipal load is put in place. Corona claims no such express statutory now exists.

Modesto opposes imposition of *any* DWR-related surcharges, either for Bonds or ongoing power costs. Modesto also opposes any utility-related costs beyond those fees specifically authorized by AB 1890.

B. Discussion

As explained below, we conclude that authority exists for this Commission to impose a CRS on MDL customers as outlined herein. Although DL has different characteristics from DA, both forms of load result in departures from IOU bundled service and raise similar concerns regarding the potential shifting of costs to bundled customers. As we did for DA customers in D.02-11-022, we conclude that imposing cost responsibility on MDL customers is warranted in order to hold such customers responsible for their share of the identified costs, and to avoid cost shifting among customers.

Although the criteria and basis for applying a CRS to municipal load is based on the record in this phase of the proceeding, the determination of specific cost elements shall rely upon the modeling methodologies adopted in D.02-11-022 applicable to DA customers, in conjunction with other companion proceedings.[17]

In the interests of avoiding cost shifting, we shall hold such MDL customers responsible for their fair share of costs necessary to achieve the goal of bundled ratepayer indifference. Some parties have argued that because MDL represents only *de minimus* amount in comparison to total bundled load, no significant cost shifting would result from exempting MDL from CRS. We reject such arguments. Cost shifting is not determined by how large any resulting cost effects are, but involves consistent application of a legislatively mandated intent independent of the specific magnitude of load.

We also reject the claim of parties that MDL customers were not served proper notice of cost responsibility until March 29, 2001, or (in the case of Modesto) that proper notice has even now not yet been served. We find that all electric consumers within the IOU service territories were placed on notice of their potential liabilities for DWR's procurement costs when the Legislature enacted SB 7X on January 17, 2001, and were placed on further notice by the enactment of AB 1X on February 1, 2001, authorizing DWR to continue its procurement program through December 31, 2002. With respect to the HPC, we accept the date of March 29, 2001 for purposes of serving notice since it is outside the scope of the above-mentioned legislation.

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[17] These proceedings include A.00-11-038 et al. which address the DWR revenue requirements and A.98-07-003 which adopted the HPC for SCE.

The adopted MDL CRS shall comprise the following:

(1) DWR Bond Charge. The charge for MDL customers shall be equal to the bundled customer charge pursuant to D.02-11-074 (Bond Charge Phase of A.00-11-038 *et al.*[18]

(2) DWR Power Charge representing the above-market portion of DWR power costs.[19] MDL's share of costs (a) between September 21, 2001[20] and the effective date of surcharges implemented pursuant to this order, and (b) prospective costs beginning on the effective date of this order continuing until DWR contract costs have been paid in full.

(3) A separate charge to cover the tail CTC as explained in further detail below.

(4) For SCE only, a "Historical Procurement Charge."

The DWR Bond and Power Charge shall apply to MDL customers that took bundled IOU service on February 1, 2001, but shall exclude customers that have been served by municipalities continuously since before February 1, 2001. Municipal customers that departed the IOU prior to February 1, 2001 did not receive the benefits of DWR long-term contract power purchases and thus shall

[18] D.02-11-074 modified D.02-10-063 by exempting all residential sales below 130% of baseline usage from the Bond Charge. Implementation of the Bond Charge for MDL will become effective after the instant decision becomes final and unappealable pursuant to Section 4.3 of the Rate Agreement.

[19] The actual final amount of the DWR power charges shall be based on the specific forecast variables underlying the Navigant modeling that will be implemented through a separate implementation phase.

[20] September 21, 2001 is the date of DA suspension. As discussed in D.02-11-022, undercollections incurred prior to this date are recovered through the DWR Bond Charge.

not be assessed DWR charges. New municipal load, as defined in this order, that migrated to a municipality or irrigation district after February 1, 2001 shall bear DWR surcharges. This treatment is consistent with the approach adopted in D.02-11-022 in which we exempted "continuous" DA customers (*i.e.*, those that took DA continuously since February 1, 2001 or earlier) from DWR surcharges.

All municipal load customers subsequent to December 20, 1995, shall continue to pay tail CTC, as prescribed by statute. If a municipality extends existing service territories into currently undeveloped areas of the IOU service territories then, consistent with Public Utilities Code Section369,[21] customers taking service in these areas should be responsible for CTC.

MDL customers that departed from SCE's system after March 29, 2002 shall be responsible for paying an HPC. We agree that by virtue of the ALJ ruling issued as of this date, MDL customers had notice served that they were potentially responsible for HPC. MDL customers departing prior to March 29, 2002 shall not pay an HPC.

The cost-per-kWh determination of the DWR surcharge elements applicable to DA customers pursuant to the approach adopted in D.02-11-022 shall serve as the basis for determining the MDL CRS. Further proceedings will be required to develop more specifically a process for identifying, billing, and collecting the CRS from the applicable MDL customers, as explained in Section V.C. below.

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[21] Section 369 states that the obligation to pay CTCs is not avoided by either the formation of a local publicly owned electrical corporation after December 20, 1995 or by annexation of any portion of an electrical corporations service area by an existing local publicly owned electric utility. (Pub. Util. Code, §369.)

III. Jurisdictional Authority for Imposing Cost Responsibility Surcharges

A. Parties' Position

Parties disagree concerning whether this Commission has the jurisdiction to impose surcharges on MDL customers for DWR costs and historic utility undercollections. The municipal parties argue that imposition of such charges on MDL customers would constitute regulation of the rates and service of municipal utilities. Thus, they argue that it is beyond our jurisdiction to impose such charges because the Commission lacks the constitutional or legislative authority to regulate municipal utility customers. They also claim that Federal Energy Regulatory Commission ("FERC") has the authority to establish stranded costs in the first instance in matters relating to cost responsibility associated with municipal customer load,[22] and that state courts have the exclusive jurisdiction over the condemnation process.

CMUA argues that applying cost responsibility surcharges on municipal customer load threatens to infringe upon the boundaries of the authority of publicly owned utilities to regulate their own operations.[23] CMUA claims that, absent an election by a public agency to utilize the Commission to determine valuation or cost determination issues,[24] the courts have exclusive

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[22] FERC Order No. 888, 61 Fed. Reg. 21,540, 21,646.

[23] *See*, *e.g.*, Ca. Const. Art. XI, §§ 7 and 9, and Art. XII, § 3. *See* also, Public Utilities Code § 10002 (municipal corporations); Water Code § 22115 (irrigation districts); Public Utilities Code § 11501 *et seq*. (municipal utility districts); Public Utilities Code § 15501 *et seq*. (public utility districts).

[24] *See* Section 1401 *et seq.*

jurisdiction to determine valuation and cost determination issues related to the acquisition of IOU property by a publicly owned utility.

Corona and CMUA rely on *County of Inyo v. Public Utilities Commission*[25] to support its argument that the Commission does not have the authority to impose DWR surcharges on municipal utilities.[26] This case addressed a request by Inyo County to have the Commission regulate the rates of customers within the county, which the Los Angeles Department of Water and Power (LADWP) had recently incorporated into its service territory. The State Legislature had not conferred upon the Commission the ability to regulate LADWP's rates in that instance and, therefore, it had no such authority.

Corona argues that the powers conferred upon the Commission by the State Legislature, as discussed in *County of Inyo*, are expressed, not implied, and there is no expressed authority for the Commission to regulate the municipal utility rates in this instance. CMUA argues that in order to regulate or exercise jurisdiction over publicly owned utilities, including provisions for billing customers on behalf of the IOU, the Commission must be given an *express* grant of such authority by the Legislature consistent with the California Constitution.[27]

Merced argues that the Irrigation District Act (which authorizes irrigation districts to provide for electric service to customers within the irrigation district) delegates no authority over irrigation district electric rates, charges, or services to the Commission. Under Section 369 certain load served by

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[25] *County of Inyo v. Public Utilities Com. (1980)*, 26 Cal.3d 154.

[26] Corona Opening Brief, pp. 12 – 13; CMUA Opening Brief, p. 7.

[27] CMUA relies on *County of Inyo v. Public Utilities Com., 26 Cal. 3d 154, 166 (1980) (quoting from Los Angeles Met. Transit Authority v. Public Utilities Com., 52 Cal.2d 655, 661 (1959)).*

publicly owned utilities, including irrigation districts, was made subject to the competition transition charge. Merced ID states, however, that "[i]n recognition of statutory authority and past investments," Section 374 provided exemptions for certain load served by irrigation districts.

The IOUs argue that the State Legislature has conferred upon the Commission sufficient authority to establish rates to recover stranded costs at issue here. The IOUs characterize the argument that the Commission lacks the legal authority to regulate rates of publicly owned utilities as being irrelevant. They agree that if a customer departs the IOU system for a municipal utility's system, the Commission will not regulate the rates charged for the municipal utility's services. However, they argue that the Commission can find that the customer retains its existing responsibility for unpaid costs it would leave behind and require that those costs be paid either in one-lump sum or over a period of time.

The IOUs frame the relevant issue as one of cost responsibility of MDL customers and the charges that the IOUs — not the publicly owned utilities — may ask those consumers to pay. PG&E does not consider it to be municipal regulation for the Commission to require IOUs' departing load, to be held responsible for payment of the DWR and other costs at issue in this proceeding.[28] PG&E argues that the Commission has the authority under Sections 451, 453, and

[28] See, e.g., *ALJ Ruling Setting Procedural Schedule* (issued Mar. 29, 2002, in A.00-11-038 *et al.*), pp. 5–6; *ALJ Ruling Denying Motion for Summary Disposition* (Sept. 27, 2002), pp. 4-5.

701 to impose responsibility for such costs on the departing load customers of the regulated IOUs.[29]

SCE similarly characterizes the relevant issues as ensuring that all customers, including customers that departs from IOU to a municipal utility, bear their fair share of the costs incurred on their behalf and that will be incurred as a result of DWR planning to provide electricity in the future.

PG&E notes that the witnesses for publicly owned utilities participating in this proceeding admitted that any costs imposed on DL customers would be charged by the regulated IOU, not the publicly owned utility.[30] On this basis, PG&E argues that any surcharges that the Commission might impose on MDL would be part of the IOUs' regulated charges, and *not* an effort to regulate the charges that the publicly owned utility require its own customers to pay.

The IOUs and ORA argue that with the enactment of AB 117, codified as Section 366.2(d) of the Public Utilities Code, the Legislature provides express authority to impose cost responsibility on retail customers that depart to municipal utilities and thereby to avoid cost-shifting. The Legislature added Public Utilities Code Section 366.2(d) to clarify its intent concerning the cost responsibility of each retail end-use customers who was a customer on or after February 1, 2001. This subsection states:

> "It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical

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[29] See also D.96-04-054 (Interim CTC decision), regarding imposing costs on Departing Load customers.

[30] Tr. p. 1861, ll. 22–26 (Modesto / Mayer); *see also* Tr. p. 1852, ll. 12–26 (Modesto / Mayer); *see also* Tr. p. 1869, ll. 3–6 (Merced / Krause); *see also* Tr. p. 1737, ll. 2–5 (WPA / Weis).

> corporation on or after February 1, 2001, should bear a fair share of the [DWR's] electricity purchase costs, as well as electricity purchase contract obligations incurred… that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature <u>to prevent any shifting of recoverable costs between customers</u>."[31]

The Municipal Parties argue that because of the "historic risk" posed by publicly owned utilities and the "unique rights and responsibilities" of irrigation districts, municipal departing load should be relieved of responsibility to pay the CRS. PG&E dismisses the relevance of such claims in relation to the fundamental cost responsibility issues in this proceeding. PG&E views the relevant question to be one of cost causation. Based on its belief that DWR did not reduce its power purchases to reflect load loss to municipal load, PG&E contends there is no basis to grant municipal departing load a special exemption from the CRS regardless of any historic risk or unique rights and responsibilities associated with these entities.

B. Discussion

We acknowledge that this Commission does not have authority to regulate the rates, charges or service of municipal utilities. Subject to limitations set forth in the California Constitution, the Legislature has plenary power to delegate authority to the Commission and to impose regulations on publicly

[31] Pub. Util. Code § 366, subd. (d)(1), emphasis added.

owned utilities.[32] The publicly owned utilities are given exclusive power to establish the rates and charges paid by their customers.[33]

We reject Municipal parties' arguments, however, that imposition of cost responsibility on departed IOU customers now served by publicly owned utilities constitutes regulation of the publicly owned utility. The surcharges that we authorize herein shall be part of the IOU tariffs, and as such, entail regulation of the IOUs. Although the surcharges will apply to customers that are presently being served by municipalities, the surcharges will be calculated, billed, and collected as a function of IOU tariffs. We defer to a separate order the specific means by which the billing and collection process will be implemented. Consequently, none of the actions we adopt in today's order constitutes regulation of rates that municipalities charge for their own service.

As a general matter and consistent with the law, the Commission may fix rates and establish rules for the IOUs.[34] We thus authorize IOU tariff charges necessary to hold MDL customers responsible for costs necessary to prevent cost shifting in accordance with AB 117, thereby ensuring that bundled customers' charges are just and reasonable consistent with Public Utilities Code Section 451. Section 453 gives the Commission the authority and responsibility to ensure that

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[32] See, e.g., Ca. Const. Art. XII, § 5; California Apt. Assoc. v. City of Stockton (2000), 80 Cal. App. 4th 699, 708 ; *see also* County of Inyo v. Public Utilities Com. (1980), 26 Cal. 3d 154, 166.

[33] See "The power of the city to fix rates to be charged those customers residing within its boundaries is incidental to the power to "establish and operate" public utility systems conferred by section 19 of article XI of the Constitution." Durant v. City of Beverly Hills, 39 Cal. App. 2d 133, 137 (1940). *See also* American Microsystems, Inc. v. City of Santa Clara(1980), 137 Cal.App.3d 1037, 1042.

[34] See, e.g., Ca. Const. Art. XII, § 3.

IOUs do not discriminate or grant any preference or advantage to particular persons, and do not maintain any unreasonable difference as to rates between localities or classes of service. Section 701 grants the Commission discretionary authority to do all things, whether specifically designated in the Code or not, "which are necessary and convenient" in the exercise of its power and jurisdiction.[35]

Pursuant to these statutes, we have authority to establish charges to recover costs incurred by DWR. Moreover, the State Legislature specifically stated its intent in AB 117 "to prevent any shifting of recoverable costs between customers," when it enacted Section 366(d). The potential for cost shifting is not limited just to DA customers, but also implicates other load that departs from IOU service, including customers that depart bundled service after February 1, 2001 to be served by a municipality, leaving costs they helped to incur, or costs that provide them with benefits. MDL customers that left the IOU after February 1, 2001 thus come under the provisions of AB 117. In accordance with these statutory requirements, bundled customers may not be infairly charged for obligations that are the responsibility of MDL customers.

Accordingly, we find that the *County of Inyo* case is distinguishable from the issues before us here. *County of Inyo* pertained to Commission regulation of a municipal utility's rates. We do not seek to regulate the rates or charges of a municipal utility in this order. Instead, by authorizing tariff charges applicable to the IOU, we are regulating the IOU, and allocate costs. The fact

[35] See also Cal. Const. Art. XII, §§ 5, 6 (granting the Legislature plenary power to confer additional authority upon the Commission, and giving the Commission power to fix rates, allocate costs, and establish rules for public utilities subject to its jurisdiction).

that the IOU must bill and collect the CRS from customers that have departed IOU bundled service after February 1, 2001 does not preclude us from authorizing the IOU to recover these amounts. Thus, nothing in this order conflicts with *County of Inyo.*

The DWR costs for which MDL customers bear responsibility include both past undercollections as well as an ongoing cost component. Water Code Section 80002.5 states that "[i]t is the intent of the Legislature that power acquired under this division shall be sold to all retail end use customers served by electrical corporations, …." AB 1X provided for funds to DWR through charges for the electricity that it purchased on behalf of retail end-users. AB 1X requires that DWR include in its revenue requirement ". . . amounts necessary to pay for power purchased by it . . . ." (Water Code, § 80134, subd. (a)(2).) Thus, consistent with the Water Code and AB 117, MDL customers bear responsibility for those costs.

CMUA argues that AB 117 relates to "direct access" (known as "community choice aggregation"), an arrangement that contemplates a continuing service relationship between the customer and the investor-owned utility. CMUA claims that AB 117 contains no express grant of authority relating to municipal customer load, and that there is no specific reference therein to service provided by publicly owned utilities.

While most of the code sections in AB 117, involve community aggregation programs, Pub. Util. Code § 366.2(d) is about XXX XXX took bundled service on or after February 1, 2001, and not XXX. Rather, this code section expressly applies to customers that took bundled service as of February 1, 2001. The grant of authority is framed in the general context of bundled IOU customer as of February 1, 2001, not merely as a DA or community aggregation customer. AB 117 does not carve out exceptions from cost responsibility for customers departing to a municipal utility. Moreover, since authorizing IOU tariffs does not constitute regulation of a municipality, we find the argument inapplicable that AB 117 provides no express authorization to regulate *municipal rates.* The fact that customers depart IOU service subsequent to that date does not foreclose our authority to recognize the preexisting obligation of the customer and to require them to pay a fair share of DWR costs, as required by law. Pursuant to Section 366.2(d), therefore, MDL customers come within the jurisdictional reach of cost responsibility for DWR charges.

Merced argues that Section 366.2(d) must be read in conjunction with Water Code Section 80104. While Section 80104 may authorize recovery of DWR Power Charges from utility customers, Merced interprets it as precluding recovery of future costs, such as a DWR Power Charge, from departing customers. Merced argues that because customers who leave an IOU for an irrigation district stop taking delivery of DWR power, they incur no liability for the costs of prospective DWR power that they never receive. Because Section 80104 imposes DWR cost responsibility "*upon delivery*" of power to a customer, Merced argues that cost responsibility cannot attach without delivery. Merced thus claims that irrigation district customers cannot be required to pay DWR Power Charges after they depart an IOU and cease taking delivery of power purchased under DWR contract.

We reject such arguments. Cost responsibility does not cease to apply to MDL customers simply because they do not currently consume DWR power. Such a conclusion contradicts the principles of cost responsibility and bundled customer indifference adopted in D. 02-03-055. Section 366.2(d) imposes cost responsibility not just for delivered DWR "purchase costs" but also "purchase contract obligations incurred". Thus, cost responsibility includes ongoing costs resulting from "contract obligations" made during 2001 when DWR was entering into purchase commitments covering several years. Those obligations require that power under the contract continues to be purchased even though priced above-market.

To the extent off-system sales of such power yield a net loss, we determined that DA customers share in such loss even though they do not currently consume power under DWR contracts. This is because DWR entered into on behalf these contracts for power of these customers while they took bundled service customers. In similar fashion, MDL customers must bear responsibility for a share of ongoing above-market costs resulting from prior DWR contract obligations even though they do not currently consume DWR power.

IV. Elements of Cost Responsibility Applicable to MDL Customers

A. DWR Bond Charge

Pursuant to AB1X, the State of California has sold bonds to finance DWR's undercollections.. The California Water Code authorizes the Commission to implement recovery of both of DWR Bond and Power charges so that DWR can recover its costs incurred from retail end use customers in the service territories of the three major IOUs (Water Code, §§ 80110 and 80134).

In D.02-02-051, the Commission adopted a "Rate Agreement" governing the terms by which the Bonds would be administered, and establishing a framework for discharging DWR's and the Commission's statutory obligations set forth in AB 1X, as amended by SB 31X (referred to hereafter as "the Act"). Under the Act, the Commission must impose charges on electric customers sufficient to compensate DWR for its costs under the Act, including power procurement, and bond principal and interest.

Revenue streams both from bond and power charges were necessary for DWR to support bonds with investment-grade ratings. D.02-11-074 (amending D.02-10-063 on rehearing) adopted the process to implement DWR Bond Charges for bundled customers. D.02-11-022 adopted Bond Charges for DA customers. DWR Bond Charges applicable to MDL customers are being addressed in this phase of the proceeding.

1. Parties' Position

The IOUs and ORA propose to charge MDL customers for DWR Bond Charges on the same basis as authorized for bundled and DA customers. These parties argue that MDL customers bear responsibility for Bond Charges in conformance with AB 117 in order to avoid cost shifting to bundled customers. The IOUs and ORA propose that the same Bond Charge apply to MDL as is applicable to bundled customers and oppose any offset (such as that proposed for Customer Generation DL customers in a separate phase of this proceeding).

CMUA and Merced concede MDL responsibility for a share of DWR's undercollections pursuant to Water Code Section 80104. CMUA distinguishes, however, MDL customers versus the publicly owned utility currently serving such customers. Absent a voluntary agreement with the publicly owned utility, CMUA contends that any such DWR obligation is not the responsibility of the publicly owned utility. CMUA also argues that any obligation of MDL customers should be limited to DWR's historic undercollections. To the extent that the DWR Bond Charge also includes reserves for prospective purchases, CMUA opposes inclusion of such reserves from MDL cost responsibility. CMUA and Merced believe that the "Shortfall

Charge" proposed in the Settlement Agreement in the Customer Generation phase of this proceeding offers a fair estimate of the amount to assign to MDL customers.

The proposed "Shortfall Charge" equals 72% of the Bond Charge assessed on bundled customers. The 72% factor is a ratio of (1) a hypothetical bond issuance of $8.6 billion and (2) the approximate actual bond issuance, estimated at $11.95 billion. The derivation of the $8.6 billion hypothetical shortfall as set forth in Appendix C to the Settlement Agreement:

> A hypothetical … bond issue [of $8.6 billion]… would generate sufficient bond proceeds to: finance the Department's undercollections through September 20, 2001; finance the carrying costs of the undercollections from the date of cost incurrence through a hypothetical bond closing date of October 10, 2002; fund bond-related accounts at levels required to comply with the Bond Indenture; fund credit enhancement and issuance costs associated with the bonds. The sizing of the bond issue does not reflect any financing of any of the Department's power purchasing program reserves.[36]

The DWR Shortfall Charge would cover only DWR's past undercollections and related administrative, financing and carrying costs, but exclude reserve accounts that could be used for DWR forward costs and later reductions to bundled customer Bond Charges.[37] As proposed, MDL customers would pay the Shortfall Charge for the full term of the bonds although bundled customers are expected to pay a reduced Bond Charge for the last few years of

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[36] A.00-11-038, Ex. 3.

[37] *See* Opening Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group in A.00-11-038, Bond Charge Phase, at 6-15.

amortization to the extent operating reserves are used to pay down the bonds. Bundled and DA customers pre-fund deposit and reserve accounts associated with the DWR bond issue and receive the benefits of these funds over the life of the bonds. DL customers, by contrast, would neither pre-fund the reserve accounts nor receive the benefits of those funds during the life of the bonds. Settling Parties characterized the lower upfront charge as "an alternative rate design" in comparison to that applied to bundled and DA load. Merced argues that the "shortfall charge" conforms to AB 117 by charging irrigation district customers only for their "fair share" of DWR's historical electricity purchases, but no more.

Modesto claims that the Rate Agreement exempts its irrigation district customers from any DWR Bond Charges. Modesto notes that while the Rate Agreement permits Bond Charges to be assessed on electric power provided to customers of electric service providers (ESPs), it excludes public agencies such as Modesto from the definition of an ESP. On the basis of the ESP exclusion, Modesto claims customers in its service area are exempt from Bond Charges.

Corona acknowledges that a municipal customer who received DWR-procured power an IOU customer during 2001 could arguably be responsible for a portion of the DWR Bond Charge pursuant to Water Code Section 80104. Corona contends, however, that if municipal customers are subject to a DWR Bond Charge, payment of that charge should be addressed outside of this proceeding in view of the Commission's lack of jurisdiction over municipal utilities. Moreover, Corona does not believe such DWR Bond Charges should be collected by the IOUs. Instead, Corona states that municipal utilities can enter into a direct agreement with DWR that addresses the applicability and amount of any such charge, as well as the mechanism for assessing and delivering the charge.

2. Discussion

We conclude that legal authority exists for the Commission to impose a Bond Charge on MDL customers for their fair share of DWR bond-related costs. Along with broad regulatory powers under the California Constitution and the Public Utilities Code,[38] Water Code Section 80110, specifically authorizes us to impose charges on retail customers to recover DWR-related costs, including a Bond Charge. Moreover, AB 117 calls for customers that took bundled IOU service as of February 1, 2001 to bear a "fair share" of DWR costs. Since bundled and DA customers will be paying their share of the DWR Bond Charge, MDL customers that took bundled service on or after February 1, 2001 should likewise share in this obligation. Such sharing promotes bundled customer indifference and avoids cost shifting among customers in accordance with AB 117 and D.02-03-055. Bundled customers would not be indifferent to Bond Charges caused, in part, by customers that had departed the IOU for a municipal utility.

A customer may not escape Bond Charge responsibility merely by departing the IOU to be served by a municipal utility. We agree with CMUA, however, that the Bond Charge obligation applies to the MDL customer who took bundled service on or after February 1, 2001, and not to the municipal utility currently serving such customer. The Bond Charge will be billed and collected pursuant to IOU tariff, and remains an obligation of the MDL customer. The mechanisms required to implement billing and collection of the DWR Bond

Charge shall be addressed in a separate implementation phase of this proceeding.

Contrary to the argument of Modesto, the fact that a public agency is exempt from the definition of an ESP does not exempt MDL customers of the public agency from the DWR Bond Charge. While D.02-02-051 applied Bond Charges to ESPs, it did not prohibit application of the Bond Charge to entities other than customers of ESPs.[39]

We also reject Corona's claim that Bond Charges may only be assessed against MDL customers through a separate agreement between the municipality and DWR with no intervention from this Commission. As previously explained, we exercise jurisdiction to impose bond charges through IOU tariffs which is within our authority, and under the statutory authority of AB 117 and related Water Code statutes.

In D.02-11-022, we imposed DWR Bond Charges on DA customers that took bundled service after February 1, 2001. Likewise, in the phase of this proceeding on cost responsibility for Customer Generation Departing Load, the Proposed ALJ Decision would require that that qualifying load would pay the same per-kWh Bond Charge as bundled customers. Based on the reasoning set forth in D.02-11-022 and in the Proposed ALJ Decision referenced above, we

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[38] *See* generally, Cal. Const., XII, §§ 5 & 6; Pub. Util. Code, §§ 451, et seq. & 701.

[39] In D.02-02-051, we alluded to "certain suggested changes" offered by SCE "aimed at requiring certain customers of municipal utilities pay Bond Charges." We stated: "that is an issue for the legislature." The Legislature has since provided additional guidance with enactment of AB 117 that requires *all* retail customers that took bundled service on or after February 1, 2001 to bear a "fair share" of the DWR Bond and Power charges.

reject the proposal to limit MDL customers to a Shortfall Charge that is only 72% of the bundled customers' bond charge.

The Shortfall Charge is based on the invalid premise that certain reserves underlying the DWR Bonds can be separated from the historic undercollection. In D.02-11-022, we explained how the reserve accounts relate to the overall DWR Bond financing requirements, resulting in an integrated bond charge. As stated in D. 02-11-022:

> "[T]he funding of the various operating reserves at closing was a pre-requisite to actually issuing the bonds. [footnote omitted] The rating agencies insisted on the setting aside of such large sums in these accounts in order to give the bonds favorable credit ratings. Without these large set-asides, the bonds would have had lower ratings, or perhaps could not have been issued at all. An investment grade rating on the DWR Bonds is required by Water Code Section 80130. Lower ratings would have increased the interest on these bonds thus increasing their cost to DA customers. In short, DA customers received a substantial benefit from these set-asides as they enabled the bonds to be issued with favorable ratings." (D.02-11-022, p. 50.)

As explained in D.02-11-022, the hypothetical $8.6 million bond issue underlying the 72% Shortfall Charge does not reflect the financing of the DWR operating reserves. Thus, by excluding these reserve accounts, the Shortfall Charge does not account for the benefits derived from the reserve accounts that apply to all affected customers, including MDL.

Moreover, to the extent these reserves do not become available to reduce future Bond or Power Charges, any purported benefit associated with MDL customers' waiver of any future benefits of the reserves becomes illusory. Given the uncertainty as to how or to what extent the reserves may reduce charges, there is no assurance that bundled customers would ever see offsetting benefits. Accordingly, we decline to adopt the Shortfall Charge, but shall impose the full bond charge on MDL on the same basis as for bundled and DA customers.

As explained in D.02-11-074, DWR was to file by November 8, 2002, its more precise 2003 revenue requirement for bond-related costs with the Commission's Energy Division once the bonds had been placed and DWR had determined actual bond-related charges. The utilities were then to file compliance advice letters to impose a per kWh hour Bond charge on non-exempt bundled consumption delivered on and after November 15, 2002. We herein direct that the Bond Charges filed pursuant to these advice letters be applied to MDL customers in connection with the implementation of this phase of the proceeding.

B. Ongoing DWR Power Charges

In addition to MDL cost responsibility for the DWR Bond Charge, we address MDL responsibility for the ongoing costs that have continued to be incurred under DWR long term contracts. In D.02-11-022, we determined the Bond Charge covered undercollections in DWR costs incurred through September 20, 2001. Thus, a separate component to recover ongoing DWR power costs incurred subsequent to September 20, 2001 is required to make DWR whole for its ongoing costs. Pursuant to D.02-11-022, DA customers bear responsibility for a share of ongoing DWR power costs relating to the above-market commitments in excess surplus off-system sales. We consider herein the extent to which MDL bears a similar responsibility for a share of ongoing above-market DWR power costs.

1. Position of Parties

Municipal parties oppose the imposition of any ongoing DWR power charges on MDL customers. Merced claims that based on traditional cost causation principles, irrigation district customers are not responsible for ongoing DWR power charges. Merced argues that although the record is, at best, "muddy" with respect to what DWR planned for in 2001 in terms of the load that would leave the utilities to take service from irrigation districts, both DWR and PG&E were aware of some irrigation district departing load. PG&E prepared in August 2000 a multi-year forecast of load departing to Modesto and Merced Irrigation Districts which forecast was given to DWR in June 2001.

Modesto and Merced claim that DWR reduced its forecast to take into account customers leaving bundled service for alternative electric suppliers. Specifically, they claim that DWR forecasted a 2% system load reduction in 2001 and a 3% load reduction in 2002 for price response actions, which include leaving bundled service for an alternative electric supplier. (Ex. 109, p. 4; Ex. 112, p. 6.) Merced thus argues that DWR did not procure, or should not have procured, power for some level of DL for reasons other than to take DA service or to install self-generation, such as to take service from an irrigation district.

Merced witness Krause testified that between the time it began providing retail electric distribution service in 1996, and the beginning of 2001 when DWR forecasts began to be prepared, its customer count had grown to over 200, and it was serving connected peak load in the range of 40 to 60 MW. Merced argues that to the extent that PG&E or DWR failed to account for movement of such load, customers leaving PG&E to take service from an ID may be burdened with costs that should not be attributable to them.

CMUA argues that even to the extent Navigant / DWR did not make a separate MDL adjustment for price elasticity it was because the IOUs separately considered and assumed (or ought to have assumed) some level of MDL in the forecasts handed off to Navigant. CMUA thus claims that it would be unreasonable for the IOUs to argue that DWR had actually "incurred costs" for this level of MDL. While CMUA may disagree with the IOUs concerning *the magnitude* of MDL that ought to be exempted, CMUA argues that the IOUs ought to jointly agree that *some level* of Municipal Departing Load should be exempted from DWR power charges.

WPA argues that its customers should not be required to pay any DWR ongoing costs because its customers' departure from IOU service was foreseeable at the time PG&E provided its forecast load data to DWR for purposes of procurement planning. WPA is a municipal agency formed to acquire from PG&E certain electric distribution and transmission facilities. The load that WPA will serve is departing PG&E's system pursuant to PG&E's sale of these facilities to Turlock Irrigation District. PG&E's witness testified, however, that PG&E did not specifically account for the departure of WPA load when it prepared the forecast data upon which DWR relied in making its procurement decisions. PG&E believes that WPA load is properly included in forecasts underlying MDL cost responsibility because finalization of the WPA agreement still remains unresolved. WPA argues that PG&E's inclusion of WPA load is imprudent in view of the fact that PG&E had contracted with the Turlock Irrigation District to turn this load over to WPA in the near future.

ORA disputes claims that DWR did not procure power on behalf of MDL customers, and notes that neither Merced nor Modesto were able to cite to the record for the claim that DWR reduced its forecast to take into account departing municipal load.[40] TURN likewise argues that DWR's forecast load reduction in 2001 and 2002 merely reflected price elasticity in response to conservation, not the complete departure of certain customers from the system. With respect to the argument that PG&E, Navigant, or DWR *should* have accounted for departing muni load anyway, ORA notes that an expert in the area of forecasting thought the future of departing muni load was lessened due to wholesale market problems in 2001 and even Westside's contractual commitment to serve departing muni load was dependent upon unsure contingencies.

The IOUs oppose any exemption of MDL from DWR ongoing power charges, and deny that DWR took into account any anticipated departures of customers to municipalities in making its forecasts. SDG&E argues that the DWR surcharge apply to each departing group of customers that would otherwise bypass DWR costs incurred on their behalf. SDG&E argues that the benefit of any considerations in the DWR forecast for demand elasticities and conservation should reasonably accrue to all bundled customers and not to municipals.

SCE argues that DWR actual procurement is what matters here, not what it should have procured. SCE contends that the Commission must implement charges to recover DWR's revenue requirement, and cannot disallow costs to correct for what DWR should have done. SCE argues that to the extent that these costs are recovered, all customers, including MDL, must participate to avoid cost shifting to bundled service customers.

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40 Merced / Krause RT 1871:15; Modesto / Mayer RT 1857:13

2. Discussion

We conclude that MDL customers should be held responsible for a fair share of ongoing DWR power costs in order to avoid cost shifting in compliance with AB 117. We shall therefore impose a component for DWR power costs patterned after the DA CRS which covers the period since September 21, 2001. During this period, DWR has been collecting its revenue requirement through bundled customer proceeds based on power charges that were implemented in D.02-02-052 and DA CRS methodology implemented pursuant to D.02-11-022. MDL customers have not paid anything since their departure to municipal service to cover their share of past costs incurred by DWR during this period. Accordingly, a separate element must be quantified to assess the requisite share of costs on MDL customers covering their responsibility for this period. We discuss further implementation measures in this regard in Section V.C. below.

We conclude that DWR incorporated no explicit reduction in the load forecasts underlying its procurement program to reflect departure of load to municipal service. While Navigant assumed annual capacity reductions from 2001 through 2011 in Distributed Generation, Navigant's witness had no estimate of how much departing municipal load there would be over the same time.[41] Navigant witness McDonald testified that DWR assumed <u>no</u> load reductions associated with municipalization efforts.[42] McDonald stated: "We also know because how difficult it is to do things like municipalize an area, long lead times

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[41] DWR / McDonald, RT Vol. 12, p. 1498.

[42] DWR / McDonald, RT Vol. 12, p. 1499.

that it takes, and we know that there are some other – *so we did not see that that was something that we really needed to factor into the forecast*." (DWR / McDonald, RT Vol. 12, p. 1499 (emphasis added).)

Contrary to the arguments of Merced, although DWR included a certain amount of price elasticity in its forecast, we find no connection between that adjustment and MDL.[43] Navigant witness McMahon testified that, "the price-elasticity adjustment [reflected in DWR's revenue requirement] is capturing only reductions in usage, and that departing load in the form of distributed generation and direct access is modeled separately."[44] Neither Merced's nor Modesto's witnesses point to any specific evidence to show that the two-percent system load reductions for 2001 and three-percent system load reductions in 2002, which were included for price response action, represented MDL. We find no evidence of any explicit level of MDL the IOUs expected or that it was ever included in DWR's load forecast. Witness McDonald's testimony shows that Navigant did not consider MDL when it presented its forecasts to DWR. All bundled customers took energy from the DWR contracts, and we find no evidence that DWR actually contracted for less energy procurement based on the belief the current or future load would depart to publicly owned utilities.

CMUA claims the IOUs independently anticipated a certain level of MDL,[45] and on that basis, some exclusion is warranted from ongoing DWR power charges. Although IOU witnesses agreed that some implicit effects of municipalization could be embedded within load forecasts, they had no specific

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[43] Merced Opening Brief, p. 15.

[44] DWR / McMahon, Exh. 75, pp. 5 – 6.

[45] CMUA Opening Brief, p. 45.

knowledge of departing load assumptions relating to municipalization. CMUA failed to offer any specific adjustments to IOU load forecasts representing exclusion or adjustment for MDL. To the extent MDL assumptions may be implicit in the IOU forecasts that were used by DWR, those assumptions would have reduced the aggregate contract commitments made and all affected customers (including MDL) thereby benefit. Given the lack of a record as to any specific load forecast adjustment for MDL, however, we find no basis to adopt a specific CRS exclusion expressly for MDL customers.

Moreover, a specific DWR exclusion applied to MDL could create a price disparity between the IOUs and municipal utilities that could significantly accelerate the rate of municipalization. As customers migrated to the municipality to escape DWR charges, the result could be a much greater level of MDL than was implied in the IOUs' load forecasts. The result would lead to cost shifting and conflict with the stated intent of AB 117. To guard against the risk of such a result, MDL customers should bear responsibility for DWR power charges.

We find unpersuasive CMUA's argument claiming that it is inequitable to exclude as certain customer generation load from DWR's ongoing costs, (as contemplated in the proposed Customer Generation Settlement Agreement) while charging MDL. This argument fails to recognize the difference between the treatment of Customer Generation versus Municipal Load in DWR's forecasting and contracting practices. While DWR actually forecasted a specific amount of departing load associated with new customer generation, it made no corresponding MDL forecast.[46] The amount of customer generation departing load proposed to be exempt from the CRS, by contrast, is directly tied to this DWR forecast.[47]

To the extent a municipality acquires customers that an IOU would otherwise have served, the municipality reduces the amount of IOU load for which DWR incurred long-term contract expenses and commitments. Unless appropriate surcharges are imposed, this departure would enable these customers now served by the municipal utility to escape their fair share of costs incurred on their behalf and will result in higher DWR costs being assigned to all remaining customers. Therefore, since DWR incurred costs for customers' load that might prospectively be served by a municipal and made no provision for municipals taking load from an IOU, MDL customers must bear a share of DWR ongoing power charges in order to avoid cost shifting to bundled customers.

We decline to exempt WPA customer load from DWR charges. In support of its request for a special exemption, WPA claims that "[c]learly, DWR did not enter into any long term contracts with the expectation that it would need to purchase power for the load departing to TID / WPA."[48] WPA provides no evidence, however, to support this assertion.

Because the transaction contemplated with WPA has remained unresolved, PG&E reasonably assumed in its forecast that customers in the

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[46] DWR / McDonald, Ex. 72, p. 7; RT Vol. 12, pp. 1473 – 1475.

[47] Motion of the Joint Settling Parties for Adoption of Settlement Agreement and to Shorten Time for Filing Comments and Reply Comments (CGDL Settlement Agreement), R.02-01-011, dated October 17, 2002, p. 5.

[48] WPA Reply Testimony (Ex. 97), p. 6.

Westside Zone would continue to be served by the IOU.[49] The transfer of the customer load to Westside is contingent upon final approval by the Commission and / or the FERC, neither of which has occurred. (Weis / Westside, RT Vol. ______, p. 1716.) Although TID / WPA negotiated a Memorandum of Understanding (MOU) with PG&E on August 31, 2000, the transaction was unresolved prior to, and even after, passage of AB 1X. Only two of the four conditions contemplated in the MOU have thus far been met.[50] Should the Commission not approve the agreement and service area agreement by December 31, 2003, the MOU could be terminated by either party.[51]

Although the MOU was signed in August 2000, the parties did not reach sign a final purchase and sale agreement until December 18, 2001.[52] As described in the application for the proposed sale, Section 4.3 of the agreement "provides that TID will pay any other non-bypassable charges owed by Westside Zone consumers adopted by the Commission or by the Legislature prior to the Closing Date, *such as any charges for Department of Water Resources costs* or prior uncollected excess power purchase costs."[53]

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[49] WPA / DaPonde, PG&E / Keane, RT Vol. _____, p. 1686; *see also* PG&E / Keane, RT Vol. ______, pp. 1689-1690.

[50] WPA / Weis, RT Vol. _____, pp. 1716–1717.

[51] WPA / Weis, RT Vol. _____, pp. 1717 and _____. S*ee also* MOU (Ex. 96), ¶¶6.1 & 6.2.

[52] *See* Asset Sale Agreement (Ex. 99), p. 1; *see also* MOU (Ex. 96), ¶6.1.

[53] *See* Application 02-01-012 (Ex. 101), p. 18 (emphasis added); *see also* PG&E Testimony in A.02-01-012 (Ex. 102), p. 2-9 (stating that TID / WPA "has agreed to make monthly payments to PG&E to cover the non-bypassable charge obligations of the customers in the Westside Zone" and has also "agreed to pay PG&E the non-bypassable charge obligation for new customer load in the Westside Zone."). Representatives from TID, PID, and WPA signed PG&E's Section 851 application for sale of the facilities in question, pursuant to Commission Rule 35. *See* Application 02-01-012 (Ex. 101), p. 34.

Moreover, PG&E continues to serve customers within the Westside Zone and that those customers have received DWR power since January 17, 2001. In consideration of these facts, we reject WPA's claim that PG&E (and DWR) should not have anticipated continuing to serve customers in the Westside Zone. Thus, we decline to grant WPA customers an exemption from DWR's bond and power charges.

C. Tail CTCs

Another component of cost responsibility at issue for MDL customers is the "competition transition charge" (CTC). Although CTC was originally envisioned as a byproduct of an industry restructuring program to provide for an "orderly" transition to a competitive environment pursuant to legislative enacted in AB 1890,[54] that concept no longer retains its original meaning. Under AB 6X, URG portfolios are once again under cost-of-service regulation. As we concluded in D.02-11-022, however, nothing in AB 6X affects the fact that customers, including DL, must pay their applicable share of above-market qualifying facilities (QF) and purchased power costs.

Section 369 authorized the Commission to establish a mechanism for recovery of CTC as "referred to in Sections 367, 368, 375, 376, and subject to the conditions in Sections 371 and 374, inclusive, from all existing and future consumers in the [utility's] service territory …." Section 368(a) prescribed that electric rates would remain frozen at the June 10, 1996 levels, through March 31, 2002 at the latest except for residential and small commercial customer rates which were reduced by 10%. These frozen rates, along with a residual

[54] (Stats. 1996. Ch. 854).

component of rates specifically delineated as the CTC, provided an opportunity for the utilities to recover "transition costs."

CTCs were to sunset on March 31, 2002. (See Pub. Util. Code, §§ 367 et seq.) The Legislature allowed for certain exceptions to this sunset date. (See Pub. Util. Code, §§ 367, subd. (a) and 376.) D.00-06-034 (in A.99-01-016) adopted a methodology for allocating ongoing transition costs (*i.e.*, "tail" CTC) after the end of the AB 1890 rate freeze, but did not address how such amounts were to be calculated. The decision directed PG&E to implement CTC through its Phase 2 general rate case (A.99-03-014) and SCE through A.00-01-009. Since these two proceedings have been suspended or otherwise terminated, the ongoing "tail" CTC applicable to DL customer is being addressed in this proceeding. In D.02-11-022, we adopted a proxy value of 4.3 cents / kWh for purposes of computing the above-market component of Section 367 costs subject to tail CTC treatment.

1. Parties' Position

CMUA acknowledges that Section 369 makes tail CTC applicable to MDL, but denies that tail CTC is applicable to New Municipal Customer Load. A further discussion of the treatment of new municipal load is set forth in Section V.A. herein. CMUA claims that absent a voluntary agreement by the publicly owned utility, any CTC obligation does not become an obligation of the publicly owned utility.[55]

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[55] CMUA understands that some publicly owned utilities (such as the Modesto Irrigation District) have voluntarily agreed to assume certain obligations for the payment of the competition transition charge associated with Municipal Departing Load.

CMUA argues that the Commission does not have discretion, as it does with other customers, including DA, to recover costs other than "transition costs referred to in Sections 367, 368, 375 and 376…" CMUA argues, the recovery of generation-related transition costs (except for tail CTC) was bounded by time and has now come to an end: "…*uneconomic costs shall be recovered from all customers on a nonbypassable basis…provided that, the recovery shall not extend beyond December 31, 2001, except [for "tail CTC"]."*[56] CMUA believes that it would be inappropriate for the Commission to attempt to use its authority under Section 369 to "redefine" tail CTC in an effort extend the reach of these costs to Municipal Departing Load.

CMUA opposes inclusion of Western Area Power Administration (WAPA) costs within the scope of PG&E's tail CTC recoverable from MDL customers. CMUA asserts that the costs associated with the power sale to WAPA do not fit within the categories set forth in Section 369 and that only pre-existing power purchase obligations, not power sale obligations, are statutorily allowed for recovery from municipal departing load.

CMUA contends that under Section 367, December 20, 1995 is the date of reference for any qualifying power purchase agreement. Assuming PG&E's transaction with DWR can rightfully be considered a "purchase" (which CMUA believes is debatable), CMUA nevertheless believes it is denied cost recovery from MDL since the "agreement" to purchase occurred after December 20, 1995.

[56] Pub. Util. Code §§ 367, subd. (a).

Merced argues that the applicability of tail-CTC should be consistent with Section 374(a).[57] Section 374 expired on March 31, 2002 and is inapplicable. Modesto argues that transition cost recovery expired on December 31, 2001.[58] It is not clear what legislation Modesto is referring to. CTC collection continued through March 31, 2002, and as provided in Section 367, tail-CTC continues after March 31, 2002.

Merced agrees that, pursuant to Sections 367 and 369, irrigation district departing load is subject to tail CTC.[59] For purposes of this proceeding, Merced defines tail CTC based upon Section 367, and thus *limited* to the following costs: (1) employee-related transition costs (through December 31, 2006); (2) existing power purchase contract obligations (through the duration of the contract); (3) nuclear incremental cost incentive plans for San Onofre (through December 31, 2003); and (4) fixed transition amounts, as applicable. Merced opposes any effort to expand tail CTCs beyond these statutorily authorized costs.

PG&E charges a tail CTC component to MDL customers as part of its approved tariff, and proposes to continue this tail CTC. [60] PG&E disputes CMUA's claim that WAPA transactions do not properly conform to CTC

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[57] Merced Opening Brief, pp. 2, 4.

[58] Modesto Opening Brief, p. 4.

[59] 15 Tr. 1867 (Krause / Merced ID).

[60] In addition to CTC, PG&E charges MDL customers a Nuclear Decommissioning Charge and Transfer Trust Amount Charge. MDL customers do not pay the Public Purpose Program Charge pursuant to D. 97-08-056. These charges were authorized under AB 1890 and various Commission decisions.

eligibility requirements. PG&E notes that under Public Utilities Code Section 840(f), IOUs may include uneconomic costs of power purchase contracts within the definition of transition costs. Public Utilities Code Section 367(a) directs the Commission to identify and determine categories of transition costs, including those identified in Section 840(f), for collection on a nonbypassable basis from all customers by December 31, 2001. Section 367(a) further provides that collection of certain transition costs — or "tail CTC" — could extend beyond December 31, 2001. Included among those costs eligible for "tail CTC" treatment are power purchase obligations.[61]

PG&E contends that the terms of the PG&E / WAPA contract fit within the eligible transition cost definition articulated by the Commission in D.97-11-074, and that CMUA's objection to the inclusion of these costs in tail CTC should be rejected.

SDG&E does not recommend any change from its existing application of CTC to MDL customers through its approved Electric Department Tariff Rule 23. SDG&E's CTC is collected in a prescribed manner that reflects the fact that SDG&E has ended its rate freeze. SDG&E argues that leaving the application of CTC to DL customers unchanged and adopting a DWR bond and power charge will not result in any double billing of costs.

In its initial testimony, SCE proposed that the tail-CTC component be based on costs associated with SCE's URG portfolio, as well as any other costs identified in Section 367, in order to recognize passage of Assembly Bill 6, First Extraordinary Session (AB6X) of 2001-2002. AB6X required SCE to retain its

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[61] Specifically, Public Utilities Code Section 367(a)(2) provides for transition cost recovery of power purchase obligations for the duration of the contract.

remaining generation assets and the Commission included SCE's Qualifying Facility and Interutility Contract costs in the adopted ratemaking for URG costs. SCE is amenable, however, to basing the calculation of tail-CTC on a strict interpretation of Section 367, as proposed by CMUA.

2. Discussion

We shall direct the IOUs continue to charge tail CTC to MDL pursuant to their approved tariffs. We address the applicability of tail CTC to new municipal load in Section V.A. herein.

In D.96-04-054,[62] we determined that CTC should be borne by all customers, including departing load customers, in rough proportion to the benefits they received. The fact that some departing load customers subsequently took service from a publicly owned municipality does not relieve them of responsibility for CTC costs as determined by D.96-04-054.

Moreover, the provisions of AB 1890 expressly provide for the recovery of CTC from DL customers, including those that migrate to municipal utilities. The need to address whether the Commission had exceeded its authority in D.96-04-054 was made moot by the subsequent passage of AB 1890, as noted in D. 97-11-031.[63]

Section 367 provides for the recovery of CTC, and Section 369 specifies that the obligation to pay ongoing CTC cannot be avoided by "the formation of a publicly owned electrical corporation on or after December 20, 1995." The Commission's authority to impose such charges thus stems from the

[62] 65 CPUC2d, 596, Re: Proposed Policies governing restructuring California's Electric Services Industry and reforming regulation.

[63] D.97-11-031, p. 7.

prior customers' status as bundled customers of an IOU, and does not presume any jurisdiction over the regulation of rates, charges or services offered by a publicly owned municipal utility. The costs that are relevant in this proceeding to the departing load customers relate only to IOU service received by these customers over which the Commission exercises jurisdiction, and not the ongoing service they are currently receiving from a publicly-owned utility.[64]

We agree with PG&E that WAPA costs are properly included within CTC applied to MDL. This finding is consistent with D.02-11-022 in which we determined that WAPA contract costs were a CTC component applicable to DA customers. (*See* D.02-11-022, p. 137.) This treatment is also consistent with D.97-11-074 in which the Commission stated:

> PU Code §367 affirms the Preferred Policy Decision finding that the utilities are authorized to collect the ongoing transition costs resulting from the difference between contract prices with QFs and the Power Exchange market-clearing price.[65]

This description is thus consistent with the inclusion of WAPA costs in the tail CTC.

Later in the same decision, we equated QF contracts to the utilities' power purchase contracts with other utilities, irrigations districts or water agencies:

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[64] The timing of the end of the "rate freeze" pursuant to Section 368, the corresponding impact on transition cost recovery, and the definition of what were formerly considered stranded costs are issues that are being considered in A.00-11-038 *et al.*, in the rehearing of D.01-03-082, as ordered by D.02-01-001.

[65] D.97-11-074, p. 125; 76 CPUC2d 627, Interim Opinion: Transition Cost Eligibility.

> PG&E . . . [has] various purchased power contracts with other utilities, irrigation districts, or water agencies. Similar to the treatment of QF contracts, both AB 1890 and the Preferred Policy Decision provided for the recovery of the difference between the actual payments under those contracts and the costs of comparable energy purchases from the Power Exchange.[66]

D. Recovery of Costs in Edison's PROACT Through the HPC

D.02-07-032 authorized SCE to establish a "Historical Procurement Charge" (HPC) in the matter of A.98-07-003. The HPC provides recovery of the balance in SCE's Procurement Related Obligation Account (PROACT). In D.02-07-032, as modified by D.03-02-035, SCE was authorized to apply the HPC to DA customers by reducing the DA customers' generation credit by 2.7 cents/kWh until the effective date of a Commission decision implementing a DA CRS in the instant rulemaking (R.02-01-011). This reduction in the DA surcharge credit was intended to provide for equivalent contributions between bundled and DA customers for the recovery of SCE's PROACT balance.

Because DL customers affected by SCE's HPC proposal did not receive adequate notice at the time, SCE agreed to withdraw its testimony in the A.98-07-003 proceeding regarding application of the HPC to DL customers. SCE has now presented its proposal for HPC recovery by DL customers as part of its testimony in this proceeding.

1. Parties' Positions

SCE proposes that responsibility for the HPC apply to MDL based on whether the load existed in SCE's service territory as of March 29, 2002, the

[66] *Id., mimeo.*, p. 128.

date of the ALJ ruling indicating that DL customers may bear responsibility for HPC costs. For DL customers that previously took DA service, SCE proposes that the customer pay the HPC adopted by the Commission in D.02-07-032 for its departed load.

SCE proposes that the Commission adopt the factors that SCE proposed in A.98-08-003 for DL customers that were on bundled service. SCE's bundled customers have been making payments toward recovery of the PROACT balance since June 3, 2001 when Commission-adopted surcharges were included in customers' bills. The proposed HPC will identify the relative contribution each customer group made toward the unrecovered procurement costs in the PROACT. SCE proposes a two-year amortization period, consistent with the expected time needed for the recovery of the PROACT balance from bundled customers.

SCE observes that a customer could switch from DA to bundled service just prior to the time that load departs in order to reduce its HPC obligation. SCE thus proposes that the proper rules be established in Schedule DL-NBC to eliminate such gaming opportunities. SCE proposes to address these issues in an advice letter implementing this decision.

PG&E proposes to defer a determination as to whether it is appropriate to impose a charge on all customers for PG&E's unrecovered costs associated with the energy crisis to the appropriate proceeding.[67]

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[67] Ex. 88, PG&E Testimony (Winn), p. 1-7. (Only Chapter 2 was admitted into the record in this phase of the proceeding; however Chapter 1, which references the historic undercollection, issue was admitted in the direct access phase.)

As previously noted above, the municipal parties generally oppose imposition of any HPC on MDL customers. Since the area where Merced provides electric services is located in PG&E's territory, Merced focuses its attention solely on PG&E's undercollection proposal. While Merced is prepared to address the issue of any surcharges related to PG&E's undercollection in a different proceeding, Merced opposes any assessment of such a surcharge on irrigation district departing load customers. Merced argues that, under AB 1890, PG&E knowingly took the risk that power costs might exceed sales prices, and should not now be allowed to shift that risk to its customers.

2. Discussion

Consistent with our imposition of an HPC to bundled and DA customers, we hereby correspondingly adopt SCE's proposal to apply an HPC to MDL customers. Because SCE is unable to identify the amount and identity of MDL at this point, it is not possible to determine a fixed HPC revenue requirement for MDL. Accordingly, we accept SCE's proposal to apply its proposed HPC factors from A.98-11-038 which were intended to reflect each customer group's relative contribution to the PROACT balance.

As SCE explains, because its costs and DA credit exceeded revenues recovered during most of the period from June 2000 through September 2001, the net result increased SCE's PROACT liabilities. For purposes of determining each customer group's HPC factor, SCE calculated the annual revenue requirement of the PROACT balance allocated among customer groups based on the ratio of each group's consumption relative to SCE's total system. This calculation was set forth in Table V-1 of Exhibit 76, and is reproduced in Appendix A of this order.

We shall also adopt SCE's proposal to apply to the HPC to MDL customers that departed the IOU on or after March 29, 2002. On that date, the ALJ ruling was issued, serving notice that DL customers faced the potential for having to pay an HPC. We shall adopt SCE's proposed two-year amortization period for HPC for MDL customers, consistent with the expected time needed to recover its PROACT balance from bundled customers.

Because PG&E has not yet placed any proposal before us concerning the treatment of its undercollection, we make no findings here concerning the ultimate disposition of any proposal that may subsequently be filed. The treatment of SCE's HPC is not intended to prejudge or set a precedent for how we may consider or dispose of cost responsibility relating to any PG&E undercollection.

V. Other Issues

A. Applicability of Surcharges to New Customer Load

1. Position of Parties

Parties disagree on the applicability of the CRS to "new load." The Municipal Parties argue that neither DWR nor CTC cost responsibility surcharges should be applicable to new municipal customer load. CMUA defines "new load" as follows:

> "Load associated with a newly constructed facility that has never been interconnected with the electric system of an investor-owned utility but instead interconnects with the electric system of a publicly owned utility, notwithstanding the fact that the load happens to be located in a geographic area that previously was part of an investor-owned utility's service area but has subsequently become served by a publicly owned utility"

The Municipal parties interpret AB 1890, and specifically Section 369, which provides for recovery of CTCs from "all existing and future consumers," as *exempting* new load from CTC responsibility as well as DWR cost responsibility.[68] CMUA acknowledges that Section 369 applies to *former* customers of the investor-owned utilities that are subsequently served by publicly owned utilities, but denies that it applies to New Municipal Customer Load

As a basis for excluding "new municipal load", CMUA cites Section 369 which states:

> The commission shall establish an effective mechanism that ensures recovery of transition costs referred to in Sections 367, 368, 375, and 376, and subject to the conditions in Sections 371 to 374, inclusive, ***from all <u>existing and future consumers</u> in the service territory in which the utility provided electricity services as of December 20, 1995***; provided, that the costs shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility. ***However, the obligation to pay the competition transition charges cannot be avoided by the formation of a local publicly owned electrical corporation on or after December 20, 1995, or by annexation of any portion of an electrical corporation's service area by an existing local publicly owned electric utility.*** (Emphasis added.)

The IOUs view the Section 369 phrase *"future consumers in the service territory in which the utility provided electricity services as of December 20, 1995"* as expressing Legislative intent to make CTC applicable to New Municipal

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[68] CMUA Opening Brief, pp. 14–18; Merced Opening Brief, pp. 29–20.

Customer Load.[69] CMUA argues, however, that this was never discussed as part of the development of AB 1890.

CMUA argues that if the Section 369 phrase "future consumers in the [investor-owned utility's] service territory…" was intended to include new municipal load, there would be no need for the succeeding sentence that reads *"[h]owever, the obligation to pay the competition transition charges cannot be avoided by the formation of a local publicly owned electrical corporation on or after December 20, 1995, or by annexation of any portion of an electrical corporation's service area by an existing local publicly owned electric utility."*

CMUA argues that this sentence, which *specifically and expressly* applies Section 369 to customers of municipal utilities would be superfluous if the phrase "future consumers in the [investor-owned utility's] service territory…" was intended to include new municipal load. CMUA thus argues that the *specific* phase is controlling over the *general* phrase"[70]

CMUA also argues that the Preferred Policy Decision[71] and subsequent Commission decisions show that neither the Legislature nor the Commission intended or contemplated that CTC would apply to New Municipal Customer Load.

CMUA claims that that it was the retail customers (*i.e.*, "consumers") of the investor-owned utilities who were on notice of and ought to have expected to

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[69] RT 1444-1451.

[70] "A specific provision relating to a particular subject will govern in respect to that subject, as against a general provision, although the latter, standing alone, would be broad enough to include the subject to which the more particular provision relates." (Rose v. State of California, 19 Cal.2d 713, 723-724 (1942)).

[71] D.95-12-063 (as modified by D.96-01-009).

bear responsibility for the competition transition charge in the Preferred Policy Decision. The Commission stated therein:

> "[W]e will institute a nonbypassable charge, called the competition transition charge (CTC), for ***all customers who are retail customers*** on or after [December 20, 1995], whether they continue to take bundled service from their current utility or pursue other options."[72]

> "[W]e also will ***require utilities*** to modify the Preliminary Statement of their tariffs to provide ***all current and new customers*** with notice of our intent to authorize collection of retail transition costs."[73]

CMUA thus argues that a service relationship with a "regulated electric utility" is required in order for the Commission to intervene and impose a charge. CMUA contends that New Municipal Customer Load, by definition, does not include a service relationship as a "retail end-use customer that has purchased power from an electrical corporation." CMUA also argues that any imposed charge should fall on customers in rough proportion to the benefits the customers "have received" from the investor-owned utility's system.

D.96-11-041 again reiterated that a service relationship with a regulated electric utility is a prerequisite to the imposition of the CTC, stating:

> "[Section] 369 requires the Commission to develop a mechanism that collects transition costs 'from all existing and future consumers,' indicating a Legislative intent that **new customers'** load would also be subject to the CTC unless they qualified for an exemption."[74]

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[72] D.95-12-063, as modified by D.96-01-009, p. 112, emphasis added. Preferred Policy Decision at 112 (emphasis added).

[73] *Id,.* at 144 (emphasis added).

[74] D.96-11-041, pp. 12-13 (emphasis added).

In discussing the treatment of new load, the Commission again stated the requirement that there be a service relationship with an IOU. A new customer was described as one who moved into PG&E's service territory and *took service from PG&E.*[75]

In D.97-06-060, as part of its discussion on jurisdictional concerns associated with a FERC-jurisdictional tariff, the Commission reiterated that service under a CPUC-jurisdictional tariff is essential for the implementation of CTC. The Commission stated that a customer would be subject to the competition transition charge "who was *[taking] PG&E service subject to CPUC jurisdiction*…and then displaced that PG&E service…"[76]

Merced also argues that while Section 369 allows the utilities to collect CTCs from future IOU customers, it does not authorize the IOUs to collect CTCs from future customers that do not take service from IOUs, such as new irrigation district customers. Merced argues that, consistent with this interpretation, the IOUs have not collected CTCs over the years from new publicly-owned utility load,[77] and that the Commission is not bound to apply Section 369 in the DWR cost context.

Witnesses for SCE and PG&E both testified that new load locating in utility territory that takes service from another provider, including a publicly-owned utility, and does not require the use of the utility's transmission and distribution system, would not be subject to CTCs applying either tariff definitions of departing load or Section 369. SCE at least *would* impose DWR-

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[75] *See id.* at 11.

[76] D.97-06-060 p. 114 (emphasis added).

[77] See, e.g., Payne / SCE, RT Vol. 13, pp. 1633-1635 & 1750-1758.

related CRS on investor-owned utility customers that move into publicly-owned utility territory and begin taking service at a new *location* that has never been served by an IOU.[78]

Merced asks the Commission to confirm that new publicly-owned utility customer load that has never taken service from and investor-owned utility and that need not take transmission or distribution service from an investor-owned utility after it locates in the publicly-owned utility service area not be subject to the DWR Bond Charge or Power Charge.

Merced further requests that the Commission affirm that a customer departing investor-owned utility service and entering a brand new site in a publicly-owned utility's service area -- which has never previously received electric service from the investor-owned utility -- not be subject to the DWR Bond Charge or Power Charge. In this scenario, Merced claims, imposing exit fees on such a customer would mean, in most cases, double cost recovery for the load at the site where the customer departed. The new customer moving into the old site will contribute toward the recovery of DWR past and future costs through bundled rates, and the departing customer will contribute toward recovery of those same costs through the DWR Bond Charge and Power Charge.[79]

The IOUs and ORA propose including "new load" in assessing DWR charges. PG&E disputes Municipal Parties' interpretation of Section 369 as limiting Commission authority to impose responsibility for costs other than CTC

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[78] See, e.g., Collette / SCE, Rt Vol. 12, pp. 1551-1553.

[79] This situation may be distinguished from the case where the customer remains at the same location and replaces a portion of its utility load with irrigation district load. Under those circumstances, no double recovery will occur if a DWR Bond Charge is imposed on the departing customer.

on municipal departing load generally (and new load specifically). PG&E argues that no evidence suggests that the Legislature intended to repeal the Commission's general ratemaking authority and responsibilities under Sections 451, 453, 701, and 728 when it enacted Section 369, or that the various statutory sections cannot be reconciled with one another.

PG&E contends that the language of Section 369 and the IOUs' tariffs permit the IOUs to charge CTCs to new load. Moreover, while unique factual circumstances made it impractical to implement CTC collection from new load, PG&E argues, such implementation issues did not constitute a waiver of the IOUs' authority to collect CTCs or other nonbypassable charges approved by the Commission from new load.

PG&E disputes CMUA's argument that the Legislature's use of the words "existing and future consumers" in Section 369 should be interpreted to preclude recovery of CTCs from new load.[80] PG&E argues that exemption of new load from DWR's costs would create a perverse incentive for publicly owned utilities to entice developers and new businesses locating within the IOUs' service areas but within the publicly owned utility's reach to take service from the publicly owned utility simply to avoid DWR's costs.[81] Meanwhile, similarly situated new load in PG&E's, SCE's, or SDG&E's service territory taking service from the IOU would pay DWR's costs as part of its bundled service rate.

PG&E claims that load served by a municipality " located in a geographic area that **previously** was part of an investor-owned utility's service

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[80] CMUA Opening Brief, pp. 15–18.

area" [82] does not properly constitute "new load" contrary to CMUA's characterizations. PG&E claims that in many cases, a publicly owned utility may serve new load in an area where the IOU still retains its obligation to serve. In addition, even where a city annexes territory in an IOU's service area, the IOU retains its county franchise rights and its obligation to serve.[83] An electric consumer that locates in such an area but takes electric service from the publicly owned utility would constitute "new load," consistent with PG&E's Preliminary Statement BB.6 (Ex. 106).

PG&E disputes CMUA's claim, however, that the Legislature, in AB 117, intended by inference to exempt new load from cost responsibility. While the first sentence of Section 366.2(d)(1) is silent regarding new load, the second sentence of that section contains a broader statement of legislative intent that is not limited to retail end use customers that purchased power on or after February 1, 2001. Specifically, Section 366.2(d)(1)'s second sentence provides: "It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers." PG&E argues that this broad legislative goal of avoiding cost shifting supports assessing these charges against new load since costs not recovered from new load would necessarily be borne by the IOUs' other customers.

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81 PG&E/Kim, RT Vol.______, p. 1451.

82 CMUA Opening Brief, p. 2, (emphasis added.)

83 *See City of Oakland v. Great Western Power Co.* (1921) 186 Cal. 570, 582; *San Francisco-Oakland Terminal Railways v. County of Alameda* (1924) 66 Cal. App. 77, 83; *Dickson v. City of Carlsbad* (1953) 119 Cal. App. 2d 809.

2. Discussion

For the assessment of CRS, we adopt a combination of the IOUs' and CMUA's of new load definition which includes new load (including any load associated wit a newly constructed facility that has never been interconnected with the electric system of an investor-owned utility) that locates within the current historic IOU service territory but purchases or consumes power supplied and delivered by a new or expanding municipal utility. The adopted definition of MDL does *not* include current or future load served by a publicly owned utility that is within the publicly owned utility's *exclusive* service territory. We shall also include "new load" added previous to February 1, 2001 within the scope of customers not subject to the CRS.

The dispute over the treatment of "new load" in the context of municipal customers raises issues different from those facing us in the DA phase of this proceeding. Since the right to acquire DA was suspended effective September 20, 2001, there was no issue regarding CRS treatment of new DA customers after September 20, 2001. By contrast, there is no suspension in effect with respect to customers' rights to migrate to a municipality or irrigation district. Thus, the question arises as to the applicability of CRS to new customers migrating into municipalities or irrigation districts in previously undeveloped service areas.

DWR entered into long term contracts to meet the net short requirements of both current and future increases in load within the defined IOU service territories as they existed on February 1, 2001. The fact that a municipality may subsequently municipalize or annex a portion of the IOU's service territory and install new facilities to serve customers moving into that annexed area raises a cost responsibility question associated with to load that had never been served by the IOU. When the installed municipal facilities are new and the geographic area was not previously populated with customers, if the development is within the geographic bounds of IOU service territory as it existed on February 1, 2001, it is not clear that it was part of the region assumed to be served by IOUs in DWR's forecasts.[84]

There are a variety of circumstances where customers enter or leave IOU territories. In some situations, a cost responsibility surcharge is required, and in some it is not. Per D.02-03-055, A surcharge is required if the customer chooses direct access, but only if that customer took bundled service after February 1, 2001. Per D.03-04-030, A surcharge is required for non-municipal departing load customers, but only if that departing load occurred after February 1, 2001, and that customer did not meet certain other requirements for exemptions. A customer moving into IOU territory from another IOU territory in California owes no CRS to the IOU it leaves, but pays any DWR charges in the new IOU's tariffed rates. A customer moving into California from out of state pays tariffed rates with DWR charges, while a customer moving out of California pays no CRS.

The common theme is that a customer which does not take service from an IOU during the period of DWR cost assessment does not pay a cost responsibility surcharge to that IOU. This is the situation with new municipal departing load. Consistency with our previous decisions requires that we not impose a CRS on these customers unless there is some other compelling basis to do so.

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[84] Ex. 41, PG&E / Keane, p. 2-5.

AB 117 requires that all retail end-use customers that purchase power from an electrical corporation on or after February 1, 2001 bear a fair share of DWR electricity purchase costs and certain utility costs (Pub. Util. Code, § 366, subd. (d)(1).). While new municipal departing load consists of retail end-use customers, these customers by definition did not purchase power from an electrical corporation on or after February 1, 2001.

Additional language in AB 117 states that it is the intent of the Legislature "to prevent any shifting of recoverable costs between customers." As stated in AB 117, these costs at issue are not just the purchase costs incurred in 2001, but the "purchase contract obligations incurred." These obligations related to multi-year contracts for supplies serving load growth beyond February 1, 2001 within the IOU service territories over a period of years. The DWR forecasts of load growth necessarily contemplated new load that would need to be served.[85]

The question is whether DWR forecasts contemplated new load that would be served by a municipality. On this point, there is some record basis to conclude whether DWR took into account such future growth. DWR's witness made it clear that it understood that there would be some level of municipal departing load. DWR assumed that the investor-owned utilities' forecasts incorporated this assumption, and, as such, the investor-owned utilities' forecast did not need to be adjusted:

> So our kind of working assumption was that kind of the movement/migration to publicly owned utilities would probably be slower than faster. And so we didn't see any reason to take -- that we had to

[85] See SCE Reply Brief, p. 26; also Exh. 41 PG&E/Keane, p. 2-3 to 2-5.

> make an adjustment or reduction in the utilities' load forecasts. [86]

The following colloquy also makes it clear that DWR was assuming that some level of municipal departing load was included in the load forecasts:

> Q. Given the past history that we've talked about concerning publicly owned utilities and certain instances where there's been a switching of customers, do you believe that it would be reasonable to assume that such switching would take place over the next 15-year time period?
>
> A. Yes.[87]

Likewise, in turn, each of the investor-owned utilities acknowledged that they had considered the issue of municipal departing load and understood its influence when developing their respective load forecasts. [88] [89] [90] [91]

In light of the fact that DWR relied upon forecasts that considered and assumed (or ought to have assumed) some level of municipal departing load, it would be reasonable to conclude that DWR had not actually incurred costs for all possible municipal departing load, and that DWR did not incur costs for some new municipal departing load.

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86 DWR / McDonald RT 1499

87 DWR / McDonald RT 1498

88 Edison / Payne RT 1658

89 PG&E / Keane RT 1770

90 SDG&E / Hansen RT 1836

91 SDG&E / Hansen RT 1842

At the same time, the record does not prove that DWR did not incur any costs for any new load that might conceivably end up with a publicly-owned utility. Scenarios can be considered whereby large amounts of current utility load and / or new developments or business parks move into or locate in territory that is annexed by publicly-owned utilities. Because the level of such activity is unknown, DWR purchases may well have assumed some of this load to be utility load, even if a certain level of new MDL was assumed due to historical trends.

Therefore, it is reasonable to establish a CRS policy for new MDL which allows some new MDL to be exempt from CRS, but not all. A reasonable way to make a distinction is to assume that historical trends will continue with current publicly-owned utilities and to not impose a CRS on new MDL associated with existing publicly-owned utilities. In order to ensure that a loophole is not created that encourages new publicly-owned utilities to develop solely to take advantage of a disparity in rates associated with DWR and historical utility cost responsibility costs – to the detriment of remaining IOU ratepayers – it is reasonable to create a different policy for new publicly-owned utilities. However, new MDL served by a new publicly-owned utility will be subject to cost responsibility surcharges. The cut-off date will be determined by whether the publicly-owned utility was established on or before the effective date of this decision.

SCE and PG&E both testified that new load locating in utility territory that takes service from another provider, including a publicly-owned utility, and does not require the use of the utility's transmission and distribution system, would not be subject to CTCs applying either tariff definitions of departing load or Section 369. However, PG&E contends that the language of Section 369 and the IOUs' tariffs <u>permit</u> the IOUs to charge CTCs to new load.

PG&E argues that unique factual circumstances made it impractical to implement CTC collection from new load. We agree with PG&E that new MDL that is subject to CRS should not be subject to CTCs.

B. Effect of Surcharges on Economic Viability of Municipal Service

1. Parties' Positions

Parties dispute the economic implications and incentives that would be created as a result of imposing CRS on MDL. Merced argues that adding DWR surcharges on top of existing utility protections will unnecessarily increase irrigation districts' cost burden and make the provision of service by irrigation districts uneconomic.[92]

SCE responds that the IOUs' customers, just as those of Irrigation Districts, must pay the costs the CRS is designed to recover. The increased cost burdens that municipal customers must bear do not make their service any more uneconomic than the IOUs' service. SCE also argues that failure to impose cost responsibility on municipals will create a perverse incentive for new municipalization, and lead to an exodus of customers from the IOUs to the municipals. SCE witness Payne testified that representatives of potential municipal utilities have told him "specifically, that if it turned out that these charges did apply, they would …as [SCE] to take the distribution back."[93] SCE witness Payne states that he has seen a number of different studies regarding the

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[92] Merced Opening Brief, p. 6, citing Merced / Krause, Ex. 112, at p. 4. Merced goes on to cite the unique benefits that the IDs provide, compared to Energy Service Providers (ESPs). (Merced Opening Brief, pp. 6 – 7.)

[93] SCE / Payne, RT Vol. 13, p. 1638.

feasibility of municipalization.[94] Payne testified that at one point during the energy crisis, around 50 of the 180 cities in SCE's service territory were studying some form of municipalization.[95]

Merced claims that the only "evidence" presented regarding the potential for exodus was broad-based speculation and a footnote reference to a consultant's report prepared for East Bay Municipal Utility District.[96] Merced argues that not only is this "evidence" vague, it also focuses on publicly-owned utilities generally and does not address specifically irrigation districts. As a result, Merced argues, this "evidence" does not overcome relevant irrigation district precedent, or focused evidence regarding the market share of irrigation districts. Merced rebuts the utilities' concern that any conclusion that departing load CRS do not apply to irrigation district departing load will create a mass departure from utility service.

CMUA likewise argues that municipal annexations provide a "commonsense response" to urban and suburban development, and occur for a variety of public interest reasons other than the price of electric power. Annexations provide an opportunity to centralize and maximize the utilization of various municipal services, and are usually considered in response to the

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94 SCE / Payne, RT Vol. 13, p. 1642.

95 SCE / Payne, RT Vol. 13, p. 1639.

96 *See, e.g.,* Payne / SCE RT Vol. 13, p. 1640; Ex. 87, PG&E Testimony (Keane), p. 2-6, n.8. (Footnote 8 also contains a quote from a "Public Power Day" (July 16, 2001) that simply expressed the then-current status of departing load's potential contribution to DWR cost recovery and does not promote or incite exodus: "[I]t has not been passed in legislation that municipal utilities that already exist, let alone new ones, are going to have to bear a full burden of responsibility on a pro-rata share basis of that money." (Quoting Cynthia Wooten, July 16, 2001.))

request of developers who desire to obtain all of the same services that other residents and businesses receive, including police and fire protection and water and sewage service. Additionally, where a municipality operates a publicly owned utility, CMUA argues, it is only logical that this service be requested as well.

CMUA argues that up until recently, the transfer of utility facilities in connection with annexations was a common, uneventful occurrence. CMUA argues that the economic impact associated with cost responsibility surcharges, however, has caused certain cities have been forced to delay annexation activity until matters relating to cost responsibility surcharges become more certain.

2. Discussion

We are not persuaded by the anecdotal evidence presented by the parties concerning the potential economic impacts of a CRS on municipal utilities and irrigation districts. The dispute between municipal parties and IOUs on this issue is at least to some degree an argument over whether the glass is half empty or half full. IOUs argue that the incentive to municipalize may turn on whether or not a CRS is imposed on MDL customers. While CMUA responds that municipalizations happen for a variety of other reasons other than the level of electricity prices, CMUA also claims that the potential for electricity surcharges for DWR costs are already delaying or discouraging plans for new municipalizations. Thus, while each side argues for an opposite result, both sides appear to agree that a CRS is of potentially significant economic consequence in the decision of whether to municipalize or whether an existing IOU customer may migrate to municipal electric service.

We find no basis to exempt MDL customers merely because the CRS may serve to some extent as a disincentive toward municipalization. Our mandate to prevent cost shifting requires that MDL customers bear their fair share of CRS costs. As discussed below, we reserve judgment on whether or to what extent a cap should be imposed on the MDL CRS as a possible remedy to address any undesirable disincentives toward municipalization. On the other hand, the absence of a CRS on MDL could potentially promote unintended incentives to municipalize merely to escape DWR charges, with the potential for cost shifting between customers.[97] We believe the potential for such a result is of great serious concern, given CMUA's admission that municipalization plans being impacted by this proceeding. Therefore a CRS is an appropriate tool to avoid unintended incentives to avoid cost responsibility.

C. Quantifying MDL CRS and Implementing Billing and Collection

1. Parties' Positions

PG&E and SCE generally concur that the Commission should adopt and apply to MDL customers the same CRS methodology as was established for DA customers in D.02-11-022, except that municipal the MDL CRS not be capped.[98] SCE states that the effect that MDL will have on its system is largely the same as the effect that of post-July 1, 2001 DA load.[99] The IOUs propose that the Commission should convene workshops to implement the process for billing and collecting the MDL CRS.[100]

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[97] As discussed in the previous section, we will require new MDL to be subject to a CRS in order to discourage new municipalization solely to avoid the CRS.

[98] The DA CRS is currently capped at 2.7 cents / kWh subject to further proceedings scheduled to conclude by July 1, 2003.

[99] SCE Opening Brief, pp. 26 – 28.

[100] SCE Opening Brief, pp. 31–32.

Municipal parties argue that the IOUs have not provided any record support demonstrating the level of costs that were incurred on behalf of departing load.[101] Corona also argues that the IOUs have not provided any detail concerning the mechanism by which the CRS would be collected from municipal utility customers.[102]

SCE responds that just because parties representing municipal interests did not participate extensively in the DA CRS phase of the proceeding, DWR and the IOUs did in fact provide such evidence in the prior phase to this proceeding regarding the CRS adopted for DA customers.[103] SCE argues, therefore, that merely because municipal parties have not provided evidence on the actual level of the CRS, does not mean that there is no record support for the level of MDL CRS.

The IOUs acknowledge that the manner in which the MDL CRS will be billed and collected is yet to be devised, but argue that does not mean that the Commission should delay a decision now establishing that MDL responsibility for the costs that have been incurred on their behalf. SCE notes that the same statement was true when the Legislature adopted Section 369, which unambiguously gives utilities the right to collect CTC from MDL.

SCE believes that a process for collecting the CRS can be developed after a decision is issued in this phase of the proceeding, and that delaying resolution of the threshold question of responsibility actually makes determination of the cost recovery mechanism more difficult. PG&E likewise

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[101] CMUA Opening Brief, p. 9.

[102] Corona Opening Brief, pp. 15 – 16.

[103] *See* D.02-11-022.

agrees that the fact that the IOUs have not yet put forth detailed implementation proposals to charge or collect CRS from MDL does not mean that MDL should be relieved of their responsibility to pay such fees.

SCE proposes that workshops be convened to initiate a further process to develop and implement measures providing for the identification, billing, and collection of CRS from MDL customers. The issues proposed by SCE for the workshop include:

- whether the CRS would be paid by (a) MDL customers served in the areas that were formally IOU service territory, (b) municipal utility acquiring those customers, or (c) wholesale distribution charges in the MDL's Wholesale Distribution Access Tariff (WDAT) service.
- Whether the CRS should be assessed in one lump sum or installments
- Means of estimating and incorporating anticipated load growth

2. Discussion

We conclude that the DA CRS costing approach adopted in D.02-11-022 provides an appropriate framework for applying a DWR ongoing power charge to MDL customers. We agree with SCE's observation that the departure of a customer has similar cost-shifting effects whether the customer migrates to DA or to a municipal utility. In D.02-11-022, we directed that workshops be convened to quantify the actual DA CRS taking into account the 2003 DWR revenue requirements based on the DA-in / out methodology adopted therein. There is no necessity to undertake an independent DWR costing analysis for MDL customers other than to identify the applicable magnitude of MDL to apply as an input into the modeling process. Therefore we shall direct that the methodological approach for determining DWR cost responsibility adopted for DA customers in D.02-11-022 be applied to encompass MDL.

In D.02-11-022, we determined the starting point of September 21, 2001 for purposes of tracking DA cost responsibility for ongoing DWR power charges (in contrast to Bond Charges). Because DA customers had not previously paid for any share of DWR power charges, we directed that a charge be assessed on DA customers for the above-market portion of ongoing DWR power costs incurred on or after September 21, 2001, to be tracked through a deferred account established by each IOU. We also approved a process for the modeling of DA cost responsibility for 2003 DWR costs based on an updated modeling run to be performed by Navigant, Inc. In similar fashion, we shall direct that the CRS implementation process for DA costs be extended to assign the applicable share of cost responsibility to MDL customers. The implementation will entail identifying the kWh volumes of MDL to be incorporated into the CRS modeling, and also to compute the CRS costs to be assigned to MDL customers for the period between September 21, 2001 and the first billing date of CRS to MDL customers.

We order a separate phase of this proceeding to address necessary implementation measures to enable the MDL CRS billing and collection to take effect. These implementation measures include the process for incorporating the applicable kWh load volumes into the modeling of CRS, and for enabling the IOUs to account for, bill, and collect the requisite charges from MDL customers. In particular, unresolved questions remain concerning the role of the municipal utility or irrigation district in facilitating and cooperating with the IOUs to enable the billing and collection process to be implemented. The ALJ is directed to issue a procedural ruling initiating further actions required to integrate MDL into the DA CRS modeling process and to implement the accounting, billing and collection of MDL CRS, as adopted in this order.

The IOUs oppose any cap on the CRS level paid by MDL customers, such as the 2.7 cents/kWh cap applied to DA load. SCE argues that municipal load provides no benefit to bundled service customers, and therefore, bundled customers should not be required to finance any cap in order to promote municipal load. Corona disagrees, claiming that municipal load offers a competitive incentive for the IOUs to offer lower prices and better service to bundled customers.

Merced argues that adding CRS on top of existing customer charges will increase irrigation districts' cost burden and render the provision of service uneconomic.[104] Merced argues that such additional cost burden will impair districts' ability to exercise their statutory authority to supply electric power services. PG&E's witness acknowledged that if the charges that irrigation district customers pay are "too high," the irrigation district may lose customers.[105]

The record is insufficient at this point to make any final determination as to whether the MDL CRS should be capped, and if so, whether that cap should equal the DA CRS cap or some other level. Further evidence is needed concerning the actual level of MDL CRS and the potential economic implications for municipal utilities. The currently adopted DA CRS cap of 2.7 cents/kWh is also in the process of being reevaluated and is subject to revision following proceedings and Commission order due by July 1, 2003. The record being developed in that phase may have potential relevance in evaluating the nature and extent of any MDL cap that may be considered.

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[104] Ex. 112, Krause/Merced, pg. 4.

[105] 14 Tr. 1784 (Keane/PG&E).

Capping of CRS obligations causes bundled customers to fund resulting CRS undercollections which must ultimately be reimbursed with interest. The need for and nature of any cap for MDL (as well as DA) customers must be weighed carefully in recognition of our obligation to achieve bundled customer indifference and to avoid cost shifting. Thus, we defer consideration of the imposition of any MDL caps pending our further developments regarding DA CRS caps and the quantification of the total MDL CRS obligation. We shall provide for appropriate opportunity to be heard on the issue of a MDL cap before finalizing the implementation of any CRS to be billed to MDL customers.

VI. Rehearing and Judicial Review

This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Public Utilities Code Section 1731(c) (applications for rehearing are due within 10 days after the date issuance of the order or decision) and Public Utilities Code Section 1768 (procedures applicable to judicial review) are applicable.

VII. Comments on the Proposed Decision

The Proposed Decision of Administrative Law Judge Thomas R. Pulsifer was filed and served on parties on ______________. Comments on the Proposed Decision were filed on _____________, and reply comments were filed on ______________.

VIII. Assignment of Proceeding

Carl Wood and Geoffrey Brown are the Assigned Commissioners and Thomas Pulsifer is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. D.02-03-055 determined that as a condition of retaining the DA suspension date of September 21, 2001, a surcharge must be imposed on DA customers sufficient to make bundled customers economically indifferent between a DA suspension date of July 1 versus September 21, 2001.

2. By ALJ ruling dated March 29, 2002, the scope of this proceeding was expanded to consider cost responsibility surcharges for "Departing Load" in order to prevent cost shifting to bundled customers.

3. DWR began buying electricity on behalf of the retail end use customers in the service territories of the California utilities: for PG&E and SCE on January 17, 2001, and SDG&E on February 7, 2001.

4. AB 1X provides for DWR to collect revenues by applying charges to the electricity that it purchased on behalf all retail end customers in the service territories of the three major utilities, as a direct obligation of these customers to DWR.

5. Consistent with AB 1X and AB 117, MDL customers that took bundled service on or after February 1, 2001 are responsible for paying a share of the DWR revenue requirements, including both previously incurred costs as well as an ongoing cost component.

6. Assembly Bill No. 117 ("AB 117"), which was signed into law on September 24, 2002. ((Stats 2002, ch. 838.) added Public Utilities Code Section 366.2(d) in order to clarify legislative intent concerning the cost responsibility of each retail end-use customers who was a customer on or after February 1, 2001.

7. Customers who took utility bundled service on and after February 1, 2001 (including those that subsequently departed to municipal service) consumed

power purchased by DWR, and thereby caused DWR to incur costs on their behalf.

8. DWR's forecast of future utility load anticipated some level of municipal departing load, but not an unlimited amount.

9. It is not necessary to impose CRS on all new municipal load of current publicly-owned utilities in areas that previously comprised IOU service territory as it existed on February 1, 2001, in order to prevent cost shifting.

10. New municipal load served with facilities installed in a previously undeveloped area do not represent departing IOU customers that previously took bundled service.

11. Unless MDL customers bear a fair share of DWR costs, there will be cost shifting among customers in violation of the intent of AB 117.

12. Pursuant to AB 1X, the State of California has sold DWR Bonds to finance over time the undercollection of DWR costs incurred during 2001.

13. DWR Bond Charges were implemented for bundled customers pursuant to D. 02-11-074, but applicability of Bond Charges for Departing Load has been deferred to this proceeding.

14. In order to avoid cost shifting pursuant to AB 117, MDL customers must bear a fair share of DWR Bond Charges.

15. Imposition on MDL customers of a "Shortfall Charge" (in lieu of a full Bond Charge) under the terms proposed in the original version of the Settlement Agreement of parties in the Customer Generation phase of this proceeding would not achieve bundled customer indifference.

16. In order to avoid cost shifting pursuant to AB 117, MDL customers must bear a fair share of the ongoing DWR power charges relating to above-market contractual commitments.

17. The DA CRS methodological approach adopted in D.02-11-022 forms a reasonable basis for determining the per-kWh MDL component of DWR power charges.

18. It is impractical for IOU's to collect "tail" CTC from new MDL.

19. A provision for "tail" CTC covering the cost categories defined in Section 367 is a necessary component of the MDL CRS in order to achieve bundled customer indifference.

20. A provision for recovery of the HPC from MDL customers as proposed by SCE reasonably holds MDL customers responsible for their share of the PROACT balance.

21. A reasonable beginning point for assigning MDL customers cost responsibility for the HPC is March 29, 2001, the date when notice was served by ALJ ruling that applicability of such costs to MDL customers was to be considered by the Commission.

22. The allocation of HPC requirements by customer group set forth in SCE's proposal and reproduced in Appendix A provides a reasonable method of assigning MDL cost responsibility.

Conclusions of Law

1. It is consistent with the intent of D.02-03-055 to impose cost responsibility surcharges on Municipal Departing Load to the extent necessary to prevent cost shifting to bundled customers based on generally similar principles as apply to DA load as set forth in D.02-11-022.

2. The Commission has broad authority under general provisions of Public Utilities Code Section 701 to regulate public utilities and to "do all things...which are necessary and convenient in the exercise of such power and jurisdiction."

3. While the Commission does not have authority to regulate the rates, charges or service of municipalities or irrigation districts, authority does exist to adopt surcharges that apply to IOUs to recover DWR bond and power charges as mandated under AB 117.

4. The Commission has authority under AB 1X and AB 117 to impose CRS on Municipal Departing Load that took bundled utility service on or after February 1, 2001 to recover DWR-related costs.

5. Consistent with the Commission's broad authority to regulate, together with §§ 451 and 453 prohibiting discrimination, bundled customers may not be arbitrarily charged for obligations that rightfully are the responsibility of MDL customers.

6. Pursuant to AB 1X and §§ 701 and 366.2(d), as well as the provisions of D.02-02-051, the Commission has legal authority to apply DWR Bond Charges on Municipal Load Customers that departed from utility service after DWR began procuring power on behalf of retail utility customers.

7. Section 369 states that the obligation to pay CTC is not avoided by the formation of a publicly owned electrical corporation after December 20, 1995, or by annexation of any portion of an electrical corporation’s service area.

8. Consistent with the imposition of an HPC to bundled and DA customers in previous Commission orders, it is appropriate to impose an HPC to MDL customers in order to avoid cost shifting.

9. New MDL does not result in cost-shifting to bundled customers if DWR did not include this load in its forecast of future utility load.

10. MDL for purposes of applying a CRS should not be defined to include new municipal customer load of existing publicly-owned utilities

11. Existing publicly-owned utilities are those publicly-owned utilities formed before the effective date of this decision.

12. The elements of cost responsibility as set forth in the order below should be applied to MDL customers in order to avoid cost shifting in accord with the Legislative's intent set forth in AB 117.

13. The issue of whether or to what extent to cap the MDL CRS should be deferred pending further developments with respect to the DA CRS cap and the quantification of the MDL CRS obligation.

14. This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Public Utilities Code Section 1731(c) (applications for rehearing are due within 10 days after the date of issuance of the order or decision) and Pub. Util. Code Section 1768 (procedures applicable to judicial review) are applicable.

O R D E R

IT IS ORDERED that:

1. This order shall apply to Southern California Edison Company (SCE). Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

2. A Municipal Departing Load Cost Responsibility Surcharge mechanism is hereby adopted applicable to designated customers that took bundled service on or after February 1, 2001 in the service territories of PG&E, SCE, and SDG&E and subsequently departed to be served by a "publicly owned utility " as defined by Section 9604(d).

3. The adopted MDL CRS shall be composed of the following elements:

a. DWR Bond Charge, applied on the same per-kWh basis as adopted for bundled customers pursuant to D.02-11-074, applicable to MDL customers in the IOU service territory as it existed on February 1, 2001.

b. DWR Power Charge, applicable to MDL customers in the IOU service territory as it existed on February 1, 2001

c. Tail CTC covering the components specified in Section 367, applicable to MDL customers in the IOU service territory as of December 20, 1995.

d. HPC component (for SCE service territory only), as set forth in Appendix A of this order, applicable to MDL customers that departed the IOU service territory after March 29, 2002.

4. The adopted MDL CRS for new MDL of new publicly-owned utilities shall consist of the elements delineated in Ordering Paragraph 3(a),(b) and (d).

5. The DWR ongoing power charge shall be applicable for above-market DWR power costs incurred beginning September 21, 2001, and continuing until bundled customer indifference has been achieved.

6. MDL customers subject to CRS shall not include those consisting of new municipal load formed within areas comprising the IOU service territory as it existed on February 1, 2001.

7. The MDL CRS shall be subject to updating and true up in accordance with the processes and procedures as adopted for updating the DA CRS in D.02-11-022 or applicable successor decision.

8. The per-kWh DWR Bond Charge component of the MDL CRS shall be calculated and implemented in a manner consistent with the Bond Charges for bundled customers implemented by advice letters filed on November 15, 2002 pursuant to D.02-11-074.

9. The Bond Charge shall take effect for MDL customers only after this decision becomes final and unappealable pursuant to Section 4.3. of the Rate Agreement.

10. The DWR Power Charge component of the MDL CRS shall be determined in accordance with the DA-in/out methodology adopted for DA customers in D.02-11-022.

11. Interest charges shall accrue on the unpaid balance due under the DWR Power Charge component of the MDL CRS for the period September 21, 2001 through the effective date that surcharges take effect pursuant to this order, and continuing until bundled customers have been fully reimbursed for all applicable charges of principal plus interest due from MDL customers.

12. The interest rate shall be used for computing interest accruals due from MDL customers to bundled customers shall correspond to the same interest rate applied for DA interest accruals.

13. The ALJ shall issue a procedural ruling initiating further actions necessary to integrate MDL into the DA CRS modeling process and to implement the tariff filing, billing, collection, and accounting for the MDL CRS.

14. The determination of whether or to what extent the MDL CRS should be subject to a cap is deferred for a separate order pending further record development.

This order is effective today.

Dated _____________________, at San Francisco, California.

APPENDIX A
Derivation of HPC Applicable to MDL Customers That Previously Took SCE Bundled Service

Rate Group	2001 Forecast GWh	TRA Allocator	PROACT Rev. Req. ($M2)	Allocated PROACT Revenue ($M2)	HPC Rate for DL (c/k Wh)
Domestic	24,456.2	30.04%		$582.1	2.380
GS-1	4,166.0	5.19%		100.5	2.412
TC-1	173.9	0.25%		4.8	2.740
GS-2	21,996.3	29.64%		574.5	2.612
TOU-GS	523.9	0.68%		13.1	2.509
LSMP	26,860.0	35.75%		692.9	2.580
TOU-8-Sec	8,955.8	11.91%		230.8	2.577
TOU-8-Pri	6,997.8	8.73		169.2	2.418
TOU-8-Sub	7,931.9	9.45%		183.1	2.308
Large Power	23,885.5	30.09%		583.2	2.441
PA-1	621.7	0.64%		12.4	2.001
PA-2	592.4	0.65%		12.6	2.123
AG-TOU	884.9	1.16%		22.5	3.542
TOU-PA-5	718.0	0.87%		16.9	2.359
Ag. & Pump	2,817.0	3.33%		64.4	2.288
Street Lights	561.3	0.79%		15.4	2.738
System	78,580.0	100.0%	$1,937.9	$1,937.9	2.466

CERTIFICATE OF SERVICE

I certify that I have by mail this day served a true copy of the original attached Proposed Decision of Commissioner Brown on all parties of record in this proceeding or their attorneys of record.

Dated April 22, 2003, at San Francisco, California.

/s/ VANA WHITE

Vana White

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.